BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:	)
	) Docket No. 09-IEP-IJ
Preparation of the 2009	)
Integrated Energy Policy Report	)
(2009 IEPR)	)

JOINT IEPR AND ELECTRICITY AND
NATURAL GAS COMMITTEE WORKSHOP

NATURAL GAS PRICE VOLATILITY AND
POTENTIAL IMPACTS OF CARBON REGULATION ON THE GAS MARKET

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 16, 2009

9:00 A.M.

Reported by:
Peter Petty
Contract Number:

COMMISSIONERS PRESENT

James D. Boyd, Vice Chair and Associate Member, IEPR
  and Electricity & Natural Gas Committee
Susan Brown, His advisor
Jeffrey D. Byron, Presiding Member, IEPR and
  Electricity & Natural Gas Committee
Kristy Chew, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead
Ruben Tavares
Leon D. Brathwaite
Randy Roesser
Peter Puglia
Paul Deaver
Mike Magaletti
Ross Miller

PRESENTERS

Randy Roesser, CEC
Peter Puglia, CEC
Dale Nesbitt, Altos Inc.
James Osten, IHSGlobal Insight
David Hoppock, Duke University*
Eric Williams*
Professor Kenneth Medlock III,
  Baker Institute at Rice University

Public Comment

Marshall Clark, Dept. of General Services,
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* Via WebEx

I N D E X

* Via WebEx

P R O C E E D I N G S

JUNE 16, 2009 9:09 a.m.

MS. KOROSEC: I am Suzanne Korosec. I lead the Energy Commission's Integrated Energy Policy Report Unit. Those of you have been to many IEPR workshops, you are going to get tired of hearing my same spiel time after time, but it still goes on. We have got about another 20 of these before we bring it to the end.

Welcome to today's workshop on Natural Gas Issues. This is a joint workshop by the Energy Commission's Integrated Energy Policy Report Committee and the Electricity and Natural Gas Committee. The workshop is being held as part of the 2009 IEPR Proceeding. The Energy Commission is required by statute to develop an IEPR every two years that covers major energy trends and issues faced in California, and provides recommendations to help the state meet our energy goals.

The topics of today's workshop are natural gas price volatility and potential impacts of carbon regulations on natural gas for power generation. Natural gas plays a crucial role in California's energy markets, it is probably about a third of the state's total energy requirements, and it is particularly critical in the electricity sector with about half the natural gas we consume being used to generate electricity.

The notice for today's workshop contained a number of discussion questions on each topic and we are looking forward to getting good input from all the stakeholders in response to those questions.

A few housekeeping items. The restrooms are out in the atrium, through the double doors and to your left, there is a snack room on the second floor at the top of the stairs, under the white awning, and if there is an emergency and we need to evaluate the building, please follow the staff to the park that is diagonal to the building, Roosevelt Park, and wait there for the all clear signal.

Today's workshop is being broadcast through our WebEx conferencing system. Parties need to be aware that we are recording the workshop. We will make a recording available immediately after the workshop on our website and, once the written transcript is completed, that will be posted on our website, as well.

For speakers and commenters today, please make sure to speak very close to the microphones so we can make sure the folks on the WebEx can hear all the speakers, and the questions and the responses. Even though it will sound as though you are speaking very loudly, it is coming across very faint on the WebEx. We will have two opportunities for public comments today, and I will take comments from those in the room first, followed by those listening in on the

WebEx. For parties in the room, it is very helpful if you can give the Court Reporter a business card when you are done speaking so we can make sure that your name and affiliation are correct in the transcript. For people listening on the WebEx, we do have your lines muted, but we will open them during the question and answer periods, and during the public comment period. And also, if you have questions, you can send a chat to the WebEx Coordinator and they will make sure that is sent out and there will be an opportunity to answer. So with that brief introduction, Commission Boyd, I will turn it over to you for opening remarks.

COMMISSIONER BOYD: Thank you and good morning, everybody. Excuse the slight delay. As you see, there is only one Commissioner up here; the other is on his way across the street to the State Capitol, where he is going to be testifying shortly before a legislative committee. We have to do that on occasion, so… Commissioner Byron and I constitute both the Integrated Energy Policy Report Committees and the Electricity and Natural Gas Committee. Commissioner Byron happens to be Chair of both. And he may or may not be able to join us some time during the procedures today, he hopes he will, but you just never know when you are finally going to be called upon to testify. And with the chaos going on across the street, I would not even want to speculate as to when that might be. And therefore, we were doing some logistical scrambling this morning to get started here. Kristy Chew, whose nameplate is sitting there, is in the building. We talked a few moments ago and she will be joining us soon. She is an advisor to Mr. Byron and will sit through the proceedings. On my left is my principal advisor, Susan Brown. We are both long-time veterans of the natural gas issue. There are a lot of familiar faces in the audience here. Some of us go back, Lord, a decade to the original Inter-Agency Natural Gas Committee that was established during the electricity crisis. So it is a familiar subject to many folks and many of us. Interesting agenda today. Of course, we always talked about price volatility; it is part of the process out here. Hi, Kristy.

MS. CHEW: Hi.

COMMISSIONER BOYD: You have been introduced already, Kristy.

MS. CHEW: Thank you.

COMMISSIONER BOYD: I also found it novel to have -- and I am looking forward to Ruben's presentation on price forecasts under uncertainty. I think we have lived under uncertainty forever, or certainly for quite some time. And the new element that is mentioned in the notice, and on the agenda, of course, is carbon regulation, which dominates virtually everything we talk about now days. As I have said in other forums and will continue to say in various forums, there have been lots of policy drivers in California down through the years that have picked up energy issues, energy and air quality, I have always talked about we are joined at the hip, and in our business of energy and price uncertainty, price volatility, supply concerns, outside the North American Continent, it always has affected what we did, but when it comes to climate change, carbon regulation, what have you, everything else pales in significance. You cannot -- everything fits under the general umbrella of climate change issues, so it will be interesting to have that discussion today, as well. So with no further ado, I would like to get today's proceedings started. I am looking forward to hearing what folks have to say. I welcome you all to today's hearing and hope you all recognize that -- this is really a workshop; I should not have used the word "hearing." I encourage you at any point in time, if you have a matter of interest, a question, or comments, we solicit your comments, and we want this to be as moderately informal as it can be. We do ask that, if you have a comment or a question that you come to the podium there and use the microphone so that the people out there listening in can hear you. We cannot pick up anything if you shout a question from the audience. So tradition is, please come to the podium and also, for our own staff's benefit, we record these things so we can go back and see what you say on occasion, and we need the microphone to pick that up. So with that, again, welcome, and we will get started. Suzanne, I do not know if I am turning it back to you momentarily?

MS. KOROSEC: Actually, we are going right to Mr. Tavares.

COMMISSIONER BOYD: Mr. Tavares, Ruben, it is yours.

MR. TAVARES: Good morning, Commissioner Boyd. Good morning, Susan, Kristy, everybody, good morning. Again, as Commissioner Boyd said, we are going to make it as informal as possible, so if anybody has any questions or comments, just get close to the microphone and hopefully we can get your good input so that we can have a complete record.

Last month, May 14th, we had a joint committee workshop in this room where we had a number of speakers make presentations on natural gas supply and infrastructure. We learned that natural gas from shale formations in North America is plentiful. Also there are some environmental issues that we need to go over again. We had a series of presentations from natural gas cropland transporters with products detailing plans to continue bringing gas to the

West from sources either in the San Juan Basin, Permian, Rockies, or the Western Canadians basins. We also learned that in the schism for re-gasification facilities of LNG has diminished somehow, basically here in the West, although some projects continue to move forward like Oregon and LNG. After the main workshop, we had a follow-up discussion on infrastructure issues during the June 4th Natural Gas Working Group meeting. We received various comments to the staff papers from the utilities. We will read those comments and incorporate appropriate revisions to our papers before they become final.

Today, we focus our attention on natural gas prices, mainly the uncertainties of forecasting natural gas prices. Their historical volatility over the ten years and the difficulty, again, of forecasting natural gas prices. There are many variables that influence price and natural gas in the market. Some of the variables are market driven and some other are of regulatory nature. We will touch on one particular variable that will become very very important in the future and that is carbon regulation, both at the state level and the federal level. We have a couple of presentations from the staff this morning, four presentations from each person in the field and one panel discussion this afternoon that will try to answer some of the questions that we have, especially about uncertainty of forecasting. There will be a couple of opportunities for the public to make comments, one before luncheon and the other one at the end of the day. So with that, I want to go through my slides.

I think in the last workshop that we had, May 14th, we indicated that, in the early 1990s gas supply increased due to the strong introduction, mainly in the Western [inaudible] [10:52] of the basin. And at the time, prices were around $2.00 per thousand cubic feet. Later on, the gas amount increased, especially for power generation, and also the price continued to increase up to $4.00, more or less, per thousand cubic feet. Domestic natural gas production actually peaked in 2001 at 52 billion cubic feet per day. The gas demand continued to increase for the year 2000s and increased up to 60 billion cubic feet today and the price of gas again kept increasing from $5, to $6, and up to $7 per dozen cubic feet.

This graph actually shows the historical increase in natural gas demand in the United States from 1990 to the year 2008, and we can see it kept increasing up to the year 1997 more or less, and industrial gas demand actually decreased, but natural gas amount for electricity generation kept increasing, and we have here from EIA a forecast of what the demand will be in the future -- again, it is just a forecast, and the EIA has provided this forecast many times.

Another graph that portrays the North American Natural Gas demand; this includes Canada and Mexico and, as you can see, we are currently up to very close to 80 Bcf per day. Historical natural gas production in the United States by different areas, we can see that the Gulf of Mexico has been declining in 2000s since 1999, but we have some compensation there from the Rocky Mountains and the Mid-Continent. So the Mid-Continent increase in natural gas supply is mainly due to the shale natural gas production.

Another graph, it shows the increases in natural gas prices over time since 1995, and we can see in 1995 the more or less year 2000-2001 energy crisis we had prices in the more or less $2-$3 per thousand cubic feet, it kept increasing in the early 2000s all the way to 2004, and now we have prices increasing again in 2006-2007 up until the last year, we see a collapse in the prices all the way down to, actually last Friday, they were under $3 per thousand cubic feet at the California border; however, I heard the day before yesterday prices are climbing up again, so who knows what…?

Now I want to draw your attention to what the directives are for the distribution as far as making some natural gas assessments and forecasts in all aspects of the energy industry and, again, that includes natural gas, and it also mentions prices at the very end of the sentence here. The California Resources [inaudible] [14:48] again directs and actually makes the point in one of the sections indicating that we must pay attention to potential problems or uncertainties in the electricity and natural gas markets. So today's topic will be exploring all of these uncertainties, and hopefully we will have some questions for the experts that are going to be making presentations later on.

Gas prices are important. And the reason they are important is because California consumes actually over 6 Bcf a day in natural gas; that is 2.3 trillion cubic feet a year. And most of the gas that California consumes, about 87 percent, comes from out of state. And the natural gas production in the state is actually decreasing. During the energy crisis in 2000-2001, California spent $19 billion on natural gas. That is an average price of about over $8.00 per thousand cubic feet; again, there were a lot of price spikes at the time, so it was expensive gas. It was almost double the cost of natural gas that we had to spend in the previous years, even though we were consuming the same. More than 40 percent of the natural gas that we consume is consumed by the power sector, and so it has a big impact on electricity rates.

What is the goal of natural gas price forecasts? We at the Energy Commission receive, very often, many requests from within the Energy Commission, and also from outside, for the natural gas price forecasts. And it is used in many events, in many venues, and for many purposes. It is used to estimate for power prices, even the California Public Utilities Commission have used in the past our price forecasts to be used for the market price reference. They used to evaluate renewable energy projects. It is used at financial institutions who will receive calls from banks that want to have a natural gas price forecast to actually lend money for energy projects. In our own state agencies, they actually ask for natural gas price forecasts to develop energy projects for the state agencies.

So how have we done? What is our record? This is just a few of the examples that we have provided in the natural gas market assessments from 1995, 1998, and then we jump a few years because we did not have data, or we could not find it, and in 2003, 2005, and 2007, and as you can see, our record has not been that great. This is the actual price of natural gas and this is our forecast from here. But actually, we are not alone.

COMMISSIONER BOYD: I was going to say, Ruben, has anybody had anything better?

MR. TAVARES: Let me show you that. Interesting, enough, in the 2005 IEPR, as part of a work that we were doing to forecasts of electricity rates, we asked the utilities, both POUs and the IOUs, to give us their own forecasts, and they all agree, but with one condition, this has to be confidential. So they applied for confidentiality to us and we gave them confidentiality, and you can see the three IOUs gave us the forecasts, and we have six POUs. And they are all over the place. One here was very [inaudible] [19:32] all the way from $7, $8, $9 per thousand cubic feet, so this is what they gave us at the time.

In the next draft, we have EIA's forecast. Again, they have -- their forecast is 1982. Back in '82, they were forecasting, you know, this kind of crisis, the nature we are down here, as you can see, and this green line indicates the natural prices of natural gas. This is all historical. So as you can see, the forecasting process has been very very difficult. So the question is, how can we move forward given that everybody asks for forecasts, all forecasts are wrong, it is virtually impossible to account for all the variables that will influence natural gas prices, given the importance that some variables change over time. They have been changing. How can we take into account this uncertainty in the forecasts and actually make those forecasts useful for the work that we need to do and that we have obligations under our own laws and our own mandates? So I am going to pose the question to everyone that is going to be making presentations today, and hopefully at the end of the day we have a good discussion with a panel of experts so that they can give us some additional guideline of how we can make all of these problems that we generate useful for the public and for the state in the future.

So with that, I would like to invite anybody who wants to make any comments or who has any questions.

COMMISSIONER BOYD: Quick question. I was gratified to see on the slide the three -- the reference to transportation use of natural gas, although it is a tiny little line, it is there. And although I am not employed by T. Boone Pickens, I do not necessarily agree with everything he says, I and the CEC are fans of natural gas playing a role in our future transportation segment, so I was glad to see that. Now, a question, Ruben. On Slide 5, you reference shale in the Mid-Continent, or the Mid-Continent line being responsible, or shale being responsible for perhaps this growth. Is the majority of the shale gas in the Mid-Continent slice, or is it distributed in other areas? I remember overlaying a map and I was reasonably familiar with all the fields, I cannot recite the names for you, but there is a fairly substantial, I thought, would be the Eastern slice.

MR. TAVARES: Actually, Commission, I am not really the right person to answer that question, but we have today through all them that have seen their presentations, and they show precisely where all that production is. So we have plenty of material today that will answer the question.

COMMISSIONER BOYD: And my last comment, you mentioned the 2005 IEPR and, of course, that was the last IEPR, and that was the year where we really honed in on the natural gas price forecast chaos that we had experienced to date, and I suddenly feel like the days echo all over again as the famous American one said. But in any event, I look forward to the experts today straightening this out. Thank you. Any folks in the audience have any questions? Here comes a question from a fellow staffer.

MR. BRATHWAITE: Good morning, everybody. I am Leon Brathwaite. I work here at the Commission. I have a question for State Commissioners. I guess I want to make a statement. So if I understand all of natural gas that is produced from shales, comes from the Mid-Continent, primarily the Barnett Shale, so that is basically the story. I mean, in the East, we have the Marcellus Shale which is not being developed, but that is about where we hang in terms of development when compared to the Barnett shale. So most of the shale gas comes from the Barnett --

COMMISSIONER BOYD: What about potential?

MR. BRATHWAITE: The potential is definitely in the East. The Marcellus shale, I think you could classify it as the mother or the father of all shales, but it is not yet as developed as the Barnett.

COMMISSIONER BOYD: Thank you.

MR. BRATHWAITE: Sure.

MR. TAVARES: I just forgot, you prepared a paper last month on shale. I forgot -- so he knows all the answers from now on.

COMMISSIONER BOYD: I read his paper, but I have already forgotten it. I forget everything --

MR. TAVARES: Thank you, Commissioner Boyd. Yes, you are in good company, I also forget those things, so… Our next presenter is part of the staff, Randy Roesser. He is going to talk about price volatility. Randy?

MR. ROESSER: Good morning. I waited about 19 years to get up to this podium. It took me long after working at the Commission to actually get to this microphone. Now I am not so sure I am happy to be here --

COMMISSIONER BOYD: Where have they been hiding you. I know, the budget guy, the budget guy, I remember you, Randy.

MR. ROESSER: Okay --

COMMISSIONER BOYD: You can get ahead.

MR. ROESSER: I am not sure if it is easier to predict natural gas prices or where the budget is going to go from here. I am sure either way --

COMMISSIONER BOYD: I was the Budget Officer of a State Department once, so you, too, can become Commissioner.

MR. ROESSER: Okay. Good morning. As I said, the past 18 months have been quite a ride for the natural gas market and natural gas prices, in particular. For those of you as old as me, you might even call it an E Ticket ride. Those of you younger that do not know what that is, you need to get out your Blackberries and you can Google that and figure that out. So if we look back at 2008, the spot prices at Henry Hub, the primary trading hub in the U.S., spot prices began the year at $7.83; by early July, they were above $13.00, and then, by the end of 2008, they were back just a little over $5.60. One year ago today, the Henry Hub spot price closed at $12.51; yesterday, it closed at $3.80. One year ago today, California's spot prices were just under $12.00 million cubic feet; yesterday, California prices closed under $3.00. So, clearly, natural gas prices have been volatile the past 12-18 months, for sure. But then I guess the question is, today, that maybe we are going to explore, is how volatile have the prices been? Do those numbers themselves clearly demonstrate the level of volatility. This is just the clinical definition of "volatility" found on the Investorwords website, everyone can read that. And while volatility is characterized as the degree of price changes, the ultimate impact to natural gas prices also depends on the influence of a couple other concepts of mean reversion, and stationary. Mean reversion simply put is a statistical measure of how fast and how strong prices migrate from either an exuberant level or a depressed level, back to a current equilibrium or accepted price level. And stationary indicates whether that price level, that equilibrium or accepted price level has been flat or constant over a period of time. So, in essence, those three factors are really what drive the actual price of natural gas.

This chart here really tells the story that volatility is not necessarily associated with high prices. Volatility really is the variance or the degree of the day-to-day price changes, not the actual level of those prices, and that is what characterizes the volatile market. Thus, periods of high prices alone are not a good indicator of whether volatility is high, or whether volatility is increasing, for that matter. For example, if you look at the chart, and if you look at the fall of 2005, if you look at the green line in the fall of 2005, or the summer of 2008, those high price levels, those spikes there, and you compare those to the price levels in December of 2001 or December of 2004, prices are not as high back then, but if you look at the orange line, you can see that the level of volatility measured on a day to day price change metric is actually lower in those years when the prices are lower. So all we have is we have the high prices, an indication that high prices then and of themselves, do not indicate higher levels of volatility.

So the other question that we looked at, and Ruben touched on this a little bit, is why is there a growing interest in natural gas price volatility. And I think the simple answer is because price volatility impacts both consumers and producers of natural gas. And here we just have a list of residential customers. Their demand is primarily driven by heating needs, with very little opportunity to adjust that demand. And certainly price spikes can hit low income households pretty hard, you know, just increasing the number of households that cannot pay their bills, default to the utilities. Of course, the IOUs do offer some assistance with balanced budget billing and other low income assistance, state sponsored, and IOU sponsored at, you know, residential. Small commercial operators are also affected by price spikes, putting stress on their operating budgets. Industrial users are often large consumers of natural gas, therefore, price spikes can have a significant impact on their operations, even driving some of their operational decisions such as the fuel switching, where available, all of that, especially in California, is a declining option. Or there have even been cases where prices have been so high or so volatile that industrial users have suspended operations because it is just too hard to plan a budget for those prices.

Power generators, the 2007 EIA Power Generation data shows that 25 percent of the U.S. and more than 50 percent of California electric power is generated from natural gas, therefore, natural gas volatility can spread and continue on and pass through to create volatile electricity crises. And finally, gas producers make product evaluation investment decisions less certain; Ruben touched on this also. Lenders who are potentially going to capitalize on some of these projects, price volatility increases the risk on the uncertainty for those lenders, therefore the cost of that capital for projects can increase and effect the gas producers, as well.

In doing the research for natural gas volatility, I took a look at historical natural gas prices, and because of the acceptance as a benchmark for natural gas domestic prices, Henry Hub's spot prices are what we are going to focus on mainly here, just as a way of consistent comparison of prices. If you look back over the last dozen years or so, prices were fairly stable, hovering around $2.00 in million cubic feet back in the late 90s; since 2000, that equilibrium or accepted price has slowly but steadily moved higher. In the last couple of years, basically being in the

$6 to $8 per million cubic feet range, all the while experiencing four significant periods of price spikes that are shown here -- winter of 2000, the crisis, February of 2003, a very short-lived price spike, the fall of 2005, and the summer of 2008.

Some of the factors that affect natural gas prices and volatility include supply and demand balances, you know, which can result from demand spikes in very cold winters, or low storage heading into winter, or falling production, or falling imports, infrastructure issues such as inadequate pipeline capacity; a good example of this was, last fall, occurred in the Rocky Mountain area where some of the spot prices of gas actually fell below a dollar per million cubic feet simply because the take-away capacity was temporarily lowered through some inspection and infrastructure work, so that had a significant effect of short-term driving prices down significantly. Weather, of course, is a principal driver of demand. It can also affect supply like that occurred in 2005 following the backpack hurricanes of Katrina and Rita, which damaged much of the supply production infrastructure in the Gulf Coast region. Regional global economic conditions can drive demand up or down. The current situation we are in now, global crisis, clearly I think it is pretty well known that most areas of energy demand are down on oil and natural gas, so that kind of effect there. Speculative trading, the level of speculative trading, I believe, has grown significantly in recent years. Last month, a debate hit the papers and the trade publications pretty steadily about the U.S. Natural Gas Fund, and EFT that reportedly held title to as much as 80 percent of the NYMEX June contracts opened interest back in May, that 80 percent has been disputed by some folks, but clearly I think the impact of just pure speculative trading has definitely entered the picture of natural gas prices and contributed to volatility of those prices. Market manipulation, of course, is always a concern, and there have been cases of that in the past that have been documented. And finally, unreliable data. The lack of sound data, of course, can lead to market actions based on market perceptions instead of market realities and, again, that can drive prices and potentially increase volatility through unreliable data.

The four major price spikes that the previous chart, this chart here, narrows the window down to this decade, starting in January of 2000, and it clearly shows the four significant price spikes that I mentioned earlier. Looking at the first one, the winter of 2001, there was several physical market factors that contributed to the winter 2000-2001 price spike. We had low storage heading into the winter peak demand, partially a result of the south and west having a warmer than normal summer temperatures which increase natural gas demand for electricity generation for cooling, and also some of the folks with purchased storage delayed purchasing that natural gas in the hopes that prices would decline in the fall, and they could get the storage in there. But unfortunately the prices did not decline as they thought, and so we did enter the winter peak with lower storage levels than we would like. The cold weather began early and it was harsh. Forty of the lower 48 states experienced below normal temperatures. And finally, several strong years of economic growth had increased natural gas demand consistently over the last previous few years.

If we look at this chart here, this shows the Southern California border prices spiked to nearly $60.00 during that same period. So if we go back, you can see the Henry Hub price here was a little bit over $10.00, and then Southern California spiked almost $60. There were two key factors that contributed to the California spike in prices during this period, and that was in August of 2000, there was a major pipeline explosion in New Mexico. It reduced California supply by about 400 million cubic feet a day, which was about six percent total of California demand. So that was one occurrence that contributed to this spike in prices just in California. And the market manipulation that we mentioned a minute ago, in a March 2003 final report, FERC documented numerous cases of market manipulation and concluded that these were a significant factor that was responsible for the California extremely high prices, it was significantly higher -- five times as high as the Henry Hub price.

In February of 2003, a short-lived price spike here, Henry Hub prices closed at just under $19, $18.85 per million cubic feet, so that was an extreme short-term spike, but like I said, it was short-lived as prices fell the very next day to just over $10, so from just under $19 to just over $10 in one trading day. Around the U.S. they are worried with higher prices, especially in the Northeast, where prices exceeded $30 per million cubic feet. The effects of low storage and high demand and infrastructure constraints, especially up in the Northeast, were compounded by the fact that a major storm came in that hit much of the U.S., spiking demand clearly in the Northeast, and the storm was so severe that, actually, there was some freezing off of wells in the Mid-Continent area, which actually temporarily curtailed supply coming out of that production region, so spiking demand and some impact to supply caused that short-term spike. But as this chart shows, it was short-lived. Because of the sudden and significant nature and degree of this price spike, FERC again looked for evidence of market manipulation, but concluded there was none. In fact, part of their final report stated that the physical and financial markets appeared to work pretty well during this price spike period.

Moving on to the fall of 2005, I think everyone knows this, the fact that Hurricanes Katrina and Rita hit; Katrina hit in late August, and Rita hit in late September, not quite 30 days later. The Gulf region was significantly impacted and caused some significant declines in natural gas production. At the time in 2005, the Gulf of Mexico offshore region was provided about 20 percent of total U.S. supply, marketed production, so disruptions in supply did exert upward pressure on natural gas prices. The peak price levels after Katrina was $15.27, and after Rita in December, we actually had $15.40 in mid-December. Just a little background on that -- Katrina destroyed 46 drilling platforms and damaged 20 additional platforms and 100 pipelines, and then a month later, Rita came in and destroyed another 69 platforms, damaged another 32, and another 82 pipelines. So the infrastructure damage to that region was quite severe by these back-to-back hurricanes, and therefore you have the huge price spikes. The break in the lines there for Hurricane and Rita, which is actually where trading was suspended for a short period of time following the actual price jumps from those hurricanes.

So 2008, last year. When I first started looking at the natural gas issues, it was obviously a very interesting year. If you look at the red line there, that is the 2008 prices, and as you can see, right from the beginning in January, the beginning of 2008, the difference in where prices were headed compared to the previous two years, the previous two years, as you can see, they pretty much flowed within the $6 to $8 band, and actually drifted lower coming out of winter, heading into the spring season a little bit, but not last year. The prices just marched northward and continued until they hit the peak in early July. But then again, looking at the backside, after July, if we hit the peak, the prices declined actually at a quicker pace than they had increased, and then if you go all the way to the right and you look at the end of the year in December, we were not only below where we were at the beginning of the year in 2008, we were below where we were the previous two years. So it was quite a roller coaster ride in 2008.

There were several fiscal market factors that contributed to this price volatility in 2008. We had low storage loads coming out of the winter; there was a shutdown at the Independence Hub, which was about a bcf per day production loss out of the Gulf of Mexico; electric generation demand continued as climate change concerns strengthened, and all of those contributed to increasing prices. And then, when we headed downward, I think this most significant market factor that contributed to the falling prices was the expansion, this sudden awareness, or the sudden production of the expanding unconventional supply, domestic supply, of shale gas and so on. It really did kind of change the dynamics and kind of turned the market on its head, frankly. It was everything from expanding the future potential reserves and what the U.S. had for domestic future production to turning around the need for LNG. We went within a six or 12-month period, went from LNG was going to be a significant necessary supply for the U.S. to not so. It just really changed the dynamic of the market. But I also believe there were several market financial factors that played a role in 2008, market speculation, I think, began to increase. We had extremely high oil prices -- oil prices hit just under $150. We had the value of the U.S. dollar, the shrinking value of the U.S. dollar, and then, of course, the global economic crisis which also then slammed the brakes on demand of natural gas. So those financial market factors also played a role, I believe, in the crisis. And we will just take a quick look here at this chart. The red line is the crude oil price, the blue line is Henry Hub natural gas prices, so if we just look at that for the moment, I think it is clear that most analysts agree that the historic explanation, or one of them, for the link between oil and natural gas prices, the ability of fuel switch, which has significantly diminished in recent years, and therefore weakening any link between all of natural gas prices. You know, I think it is a fair thing to think about, that as market speculation grows as an influence in the market, that potentially the energy commodities -- oil and natural gas, as speculative investment opportunities provide the basis for a continuing link between oil and natural gas. If you look at the green line, that is the value of the U.S. dollar. And you can see, as the prices were headed north in the first half of 2007 and 2008, you can see the value of the U.S. dollar inversely related here and falling as the prices of those energy commodities went up. And then, right when we hit the peak prices and turned around, and oil prices began to fall, and natural gas prices began to fall, you can see the dollar did a reversal and started heading northward also. So, again, I think it is more than just coincidence that that is the case, that the value of the U.S. dollar does affect demand and prices for energy commodities as speculative investments.

Finally, then, we took a look at the accuracy of past forecasts. Ruben had this chart up on his presentation. Mine looks a little prettier, the color I put in there, but… Essentially, this is the same chart that Ruben had. This is the price forecasts that EIA had back in 1982, and again you can see the white line here are the actual prices, and then all the others are the EA forecasts. As Ruben had mentioned, in the 80s, their prices tended to be higher than the actual prices, and now they have kind of migrated where a lot of the forecasts are actually below what actual prices turned out to be.

So, you know, I think forecasting efforts are certainly going to have to figure out a way to effectively recognize and consider the future of price volatility and the uncertainty of many of the physical and financial factors that contribute to price volatility, and factor that into the forecasting methods to somehow make these price forecasts more useful to policy makers and market participants. Certainly, the factors that drive price volatility are some of the same factors that are used in forecasting, and clearly there is a lot of uncertainty about the proper values to assign these variables, or, as Ruben said, even to the weight to put on the different factors as that changes potentially from year to year, or period to period. And, of course, the evolution of carbon regulation policies as significant uncertainty to the whole picture of price forecasting. The market analyst, Katie Elder, who I think is known by a lot of folks here in this room, in an

October 2008 article, simply put, stated carbon regulation changes everything. So clearly, I think that is going to play a large part in the future forecasting. Also in the paper, we examined four different natural gas price forecasts, and you can see the chart shows a wide range of prices, particularly in 2009, so right in the front end of the forecast, you can see the price forecast in 2009 range from $5.70 to over $10 per million cubic foot. That represents a 77 percent price difference, and the fact that it is so near term, that the difference is so great, I think that is just a good illustration of the uncertainty and the risk of accepting singular, date-specific, single point price forecasts for policy decisions, or business decisions, for that matter. I think it paints a picture that whoever is using these forecasts for decision making needs to be careful and understand what it is saying and what they are reading.

So finally, these are some of the issues I think that, hopefully, by the end of the day we will have a little better understanding. Some of the experts here can weigh-in on this, hopefully, and provide some valuable insight into some of these questions that are pertinent to the issue of price volatility and its effect on price forecasts. That concludes my presentation.

COMMISSIONER BOYD: Thanks, Randy. I had read your paper and thought it was quite good. Quick -- well, it is almost not a question. On Slide 7, you referenced a link between gas and oil prices, and many of us have followed that for years, and it seems to me, and you kind of said it, "experts" [quote unquote] have said, and have tended to agree for a number of years, that there is no logic for the link any longer. But it just cannot break itself, it is still tends to be there, so I think it is just the market psychology, but that is just a guess on my part, in any event, so you cannot ignore that fact, whether you like it or not. And energy pricing, when people look for a hook to grab onto, I think that is one, that and everything else, they tend to follow -- yet, the value of the dollar thing, I mean, that is just a linear event is one of --

MR. ROESSER: Well, it is interesting, when I first started researching, because I do not have this -- with all due respect -- ancient history of the relationship in the past for oil and natural gas, so basically I just started from scratch, and I can tell you that I can find extremely compelling arguments on both sides of that issue, from quite respected experts and who come to different conclusions about that relationship. So it certainly is complex and there still is ongoing debate, I do believe, on the strength of that relationship.

COMMISSIONER BOYD: Well, I am somewhat of an amateur economist, even though I am allegedly an economist at the Commission, and I have had a lot of economics in my life, and I believe very strongly in behavioral economics is a very key component of our life, that we are paying more and more attention to now. So, in any event, very good. Thank you. Questions, comments from the folks in the audience?

MR. ROESSER: Leon?

MR. BRATHWAITE: Roesser.

MR. ROESSER: I thought you had a question. Never mind. Okay, thank you.

MR. TAVARES: Thank you, Randy. Our next speaker is also part of the staff of the Commission, Peter Puglia. He is going to make a presentation on some research that he did on carbon regulation of potential impacts, especially in the power sector. So, Peter?

MR. PUGLIA: Thank you, Ruben. I have been here nine years and this is my first trip to this podium, another first is that I think I am the only presenter, or the first presenter, who uses the first last name format for his e-mail address. That is my contribution to the Energy Commission. You can do that, staff.

I spent a number of weeks reviewing studies of key federal and state legislation on the greenhouse gas impacts on natural gas generation. The policy levers, that is the term that has become the jargon up in our office, the levers mostly in legislation include these elements right here, either apply -- with economic constraints, you are either going to have them apply to economic constraints, or you are going to have markets asserting their will, which most of you are familiar with. The studies cover every one of these parameters, some of them to different degrees than others because the studies have with over-selecting, maintained their own interests and their own objectives, and the work that they do, they want to try to justify certain findings scientifically -- who would not want to do that? That is not true of all of them, I am not going to identify anybody, but some of the conclusions they come up with are modeled well, and they are documented well, and they are definitely reasonable.

The studies I looked at include one from the Energy Information Administration, Duke University, and we will be hearing from them later today, they will give what I expect will be a robust and interesting defense of their own study, the Natural Resources Defense Council also did an interesting study that, unlike the others, they did not look at any particular policy lever, they did not look at carbon caps, they did not look at renewables, they did not look at choices in fuel types, favoring natural gas over coal, they just looked at what happens if you do not do anything. And they also -- another interesting conclusion from their study that is not seen in any of this, in any of the other studies, is that they not only modeled economic impacts, they modeled what also are -- they called them "discontinuity and non-economic costs," and non-economic costs are human health, wilderness, wildlife costs, and discontinuity costs would be catastrophic to events like the break-up of the West Antarctic Ice Sheet, which could be an abrupt event and, according to their study, could dramatically increase sea levels and inundate a lot of real estate. None of the other studies did that. And the point, of course, of the NRDC study is, "Stop debating and do something." That is really what they are trying to say. They could have sent somewhere here to say the same thing. Monetizing those kinds of variables, we all probably recognize it is difficult to monetize; in fact, on wilderness or wildlife, or much less the break-up of the West Antarctic Ice Sheet. The other studies, however, from EPRI, American Gas Foundation, and the landmark opinion that the Public Utilities Commission did with the Energy Commission, the final opinion last year on AB 32, are the studies that I looked at. What I am describing here is a prevailing conclusions, this is not where we have clear and unambiguous agreement on any of these particular findings that you see up here; there is either explicit agreement amongst the reviewed studies, or it is a reasonable induction from the studies' findings; if you review the studies yourselves, you have looked at the modeling results, you will see that it is a reasonable induction that they came to each of these particular conclusions. None of this really is that surprising, certainly not these three. And also, the variables that they chose may not be the same assumptions, it shows, very considerably. But, again, the inductions are definitely reasonable. And recent developments are serving to justify these conclusions, especially if you look at what we are seeing in the West. The West Natural Gas Fire Generation is the marginal fuel component for at least 90 percent of the day, and the trend in the other inter-connects of North America is also going towards the same kind of fuel stack, getting away from coal, coal projects are being canceled, natural gas units are being proposed in their place, the results they are going to get from their own grid operations will be what we are getting from ours.

Okay, some of the differences of opinion which are -- those are actually explicit, those are not just differences of inductions, these are explicit statements that, of course, have to do with the assumptions that were used in the modeling, have to do with the results, they have to do with the models that they use. There are only two studies that use the same model, the Duke study and the EIS study both use NEMS, but that is where the similarities end. The two institutions made their own changes based on information that was either updated or that they believed is more important in attempting to justify their thesis. An example, Duke, in their modeling, they indicate there is a steep loss from the implementation of the Lieberman-Warner bill, Senate Bill 2191, which died a couple of years ago in the Senate, never came to the floor, but is instrumental in understanding what could happen to federal legislation because it passed out of the House Energy and Commerce Committee the Waxman-Markey Bill, H.R. 2454, which has the same kind of policy levers and the same objectives as the Lieberman-Warner Act, and the modeling results. EPA last month did some modeling of the Waxman-Markey Bill and said the results are similar to the Lieberman-Warner. And so, for purposes of getting educated on the consequences of such legislation, Senate Bill 2191, even though it is dead, it is still relevant to understanding what those consequences could be. Now, what Duke did in modeling the carbon caps from Senate Bill 2191, is they included retrofits of carbon captured sequestration; EIA did not do that, they did not model any carbon capture sequestration retrofits to existing power plants because they explicitly point out that the legislation is not clear as to whether that is allowed.

Duke was interested in seeing how that might be maximized, or how the carbon savings could be maximized. EIA has only the mandate, instead. It is a perfectly reasonable justification for going different routes in their modeling.

An almost uniform opinion about the effect of carbon caps on the natural gas generation cohort is that, because of its continually plummeting price, will capital costs, natural gas for our generation is going to displace nuclear renewables and coal if CCS, capital costs for coal plants are a lot higher than they are for Combined Cycle Gas Turbines. Duke disagreed and you will find out later, in better detail, one of their major findings is that natural gas fire generation is not going to do that at all. Another interesting difference is that these institutions differ on the strategies that will best minimize greenhouse gas policy costs. One I found most -- nobody else talked about -- was an American Gas Foundation study which Black & Veatch did for them, and they used an efficiency methodology that, instead of calculating the efficiency of a particular fuel in a residential commercial application, using the application itself, the AGF study looked at the energy use from the point at which the energy is generated, or produced, all the way out to the application itself. For example, a clothes dryer, instead of measuring efficiency of a clothes dryer itself, you measure if it is electric powered, you measure the efficiency of the power grid that produces electricity, the transmission losses getting electricity to the clothes dryer, and include the clothes dryer itself. The AGF study advocates heavy fuel switching from electricity to natural gas, and using that methodology of efficiency to say that your savings are considerably greater than you could ever expect from electricity. It is not a conclusion that the EPRI study focused on, nobody else looked at it, and you would not expect anybody but the gas people to look at it, but it is a rational and it is a defensible -- it is a difficult to dispute conclusion, the efficiency that they say your average get -- your average efficiency you get is 27 percent using electricity in residential and commercial applications, and you get closer to 90 percent if you just substitute natural gas and pump the gas to those applications. There is very little gas lost if you know anything about thermodynamics, and waste heat, and combustion, you would have to agree that they have a really good point.

There is an interesting -- it is in my draft paper, and it has been brought up here, too -- the Duke and the EIA studies, as I said, are the closest in the use of assumptions and methodologies, and as I have pointed out, both of them use nouns -- there are some key differences between the two studies beyond that. They both, as you see, they looked at a Senate Bill 2191 core case, which they ran. Those are not the same, you can see, in the caption below there are some important distinctions that EIA probably would sign off on these, on the Duke studies at this point because the Duke study relies on more updated natural gas production technology assumptions. The Duke study relies on updated capital cost assumptions. The EIA studies were just a few months older. No criticism there. What is interesting is that, you know, we start out looking at what on its face might seem like apples vs. apples, but in both the assumptions and the results, we are getting -- fortunately -- something different; we are getting an actual empirical distinction between the results you get from one set of assumptions and the results you get from another. And this is not insignificant for planners. If you are expecting your carbon caps to have this kind of effect on generation, as you see form EIA, where Duke says, no, you actually could get away with it, you can actually be better off, what is a planner supposed to think? Or a policy maker supposed to do? Updating assumptions, which we all know just means changing them based on your latest historical data, well, not entirely, but in large part, so in looking at quite a difference of results here that leave you pretty much lost, I would say. Some of you recognize this from the Public Utilities Energy Commission Final Opinion on

Greenhouse Gas Regulatory Strategies. Again, it is not a surprising result, it agrees with the prevailing conclusions, simply put, your natural gas price increases -- in this case, it is modeled as going from $6.00 per million Btu, it goes to $12.00, here is what you get, you get an increase in retail electricity rates in California, only, is what this modeling is, about three and a half cents a kilowatt hour. That is not interesting, but it is helpful because most of our thermal generation is already natural gas. It is doing that particularly major impact on emissions. And those of you who are familiar with the -- say a decision also recognized this -- this is the PLEXOS modeling of the entire Western grid, which is what happens when you apply a carbon price to power plant emissions, and you vary it from zero dollars to $160, politically unrealistic, I am told, but people like to see what might happen anyway.

Finally, this is part of the introduction that my draft report was -- the implications when your baselines change. Here I am just looking at EIAs annual energy outlooks between two different years, and you look at the difference in key variables, in this case, natural gas consumption and prices. Look at the change. You are going from projected consumption in the outer years, going from 5 to over 7 trillion cubic feet. And prices increase by two to three dollars for most of the forecast term. Yeah, this is where planning agencies like the Energy Commission are going to get the shaft because the consequences for this -- as Ruben and Randy showed us some of these forecasts, but what happens to renewables or efficiency programs when your market -- the market clearing price for electricity is set by natural gas -- combined cycle gas turbines, again, are setting the price 90 percent of the time, and centers for renewables or efficiency are basically -- they face a bit of a threat when the cost of generation gets so low based on a much lower forecast for price. Of course, there is a difference for contract prices for coal or for biofuels, or for natural gas ever catching up with spot prices, and these things -- these forecasts do not mean anything. But if you are a planner, you have to look at some kind of a forecast in order to set your policy, and that is what we are stuck wondering, how well will renewables for efficiency programs fare in a low gas price environment.

So the questions that these studies attempted to resolve, and for which they gave very reasonable answers, what kind of consequence do we get? Are we going to switch from coal power generation to natural gas generation? I think I hinted earlier on that we are already seeing that. It is already documented. EIA has looked at natural gas and coal generation in the Southeast United States, and they are seeing that natural gas is actually switching with coal in the dispatch stack because of the low price of natural gas relative to coal. Again, there is -- this is just a preliminary result that most of these fuels are under contract, and procurement on spot is a minor part of their cost. And California is leading the way on this trend of favoring natural gas and the thermal generation cohort. What is going to be the potential impact on gas supplies in California? And these other potential issues that I think are addressed in depth in some of the other presentations have been given in the natural gas workshops, again, relying on forecasts, and there has been some controversy about the consequences for those. There is a wild card with LNG exports. We now have the Kitimat facility permitted to export natural gas and take advantage of winter time price differentials for LNG that exceed a dollar per million Btu, it will be $2 to $3, and that is a wild card that could influence the answer to this question. And generally, the studies, as I pointed out earlier, they generally agree that there is going to be an increased demand for natural gas for electricity generation. In California, the policy is set by the Air Resources Board, their Scoping Plan, and their priority is to focus on renewables and energy efficiency measures. The result might differ in California than it would elsewhere in the United States, and the studies which focus mostly on national legislation tend to arrive at a different result. That is my presentation.

COMMISSIONER BOYD: Thank you, Peter. To me, this is quite fascinating and it is going to deserve a lot of additional review and study, particularly with our friends down the street, the Air Resources Board, and their concern. That has been my long-held feeling, that why California is heavily dependant on natural gas as [inaudible] [75:12] is a product of air quality regulations years and years ago, that drove us away from fuel oil; we never were cursed, as I like to say, with coal. And I have worried and you exacerbate that worry here about us finding ourselves overly dependent on natural gas, just because that is where we end up with regard to demand and supply and price consequences in the future. And it is going to prove to be interesting, I mean, in my tour of duty here, we have gone from gas feast to famine and back to feast, i.e., shale gas has brought us back into speculations of, you know, the [inaudible] [76:11] again in gas like it was some time ago, but there will be a debate about how much of that shale gas can really be recovered, not technologically, but due to other rules and regulations.

MR. PUGLIA: Right. Environmental complaints about the water and --

COMMISSIONER BOYD: And therefore where will we end up -- the nuclear debate will be there, the renewables issue, and I have watched for years as folks I have known for years, Air directors in other states, discovered the air quality benefits of natural gas, and slowly started driving their states in that direction, in some areas away from coal, and we watched the economics of coal head east -- or gas, rather -- head east because of the economics. This agency found itself saying we are going to need more gas in our future, we do not care where it comes from, North Saudi to West, West and LNG, and so we were great proponents of the need for LNG in California, and collectively we ran into that brick wall, concern and interest. LNG has, pardon the expression, seemed to evaporate for the near term, but it may be lurking out there in the shadows in terms of how much of that coal gas -- that shale gas -- can we get, coupled with what U.S. wide demand going to be because of carbon considerations and what have you. So anyway, it will be an interesting future for a lot of you.

MR. PUGLIA: You seem to be recapitulating the irrational exuberance of one fuel type, to the next, to the next.

COMMISSIONER BOYD: Well, in my tour of duty here, we have watched the pendulum swing violently from one end of the field to the other, and it is up to you younger people to grab that pendulum and stabilize it somewhere where you end up with my favorite expression of a mixed portfolio of fuels, so you are not overly dependent on one and, you know, the supply-demand issue does not crunch you. And I think we are doing a better job in this arena than was done nationally in the transportation fuel area that has many here today. But in any event, very good presentation, Peter. Good work.

MR. PUGLIA: Thank you.

COMMISSIONER BOYD: Comments, questions from folks in the audience? Dialogue? Agreements? Disagreements?

MS. BROWN: I guess I have a question, just a quick one. So what I am inferring from your presentation is that carbon caps are likely to increase the demand for natural gas across the country, and therefore the price. And so it is a question of how much. And then I guess my question would be, how would California's demand for natural gas compare to other parts of the country? Are we expected to feel higher than average increases in gas prices as a result of carbon caps than, say, other parts of the country? I guess that is my $64,000 question.

MR. PUGLIA: Yeah, and I will give you a qualified answer. Yeah, it is. Well, nationally -- it is a continental market, and if prices go up elsewhere in the continent, they are going to be going up here, too. There are differentials, of course, in any pricing point with

Henry Hub, but in general they are expected to go up. Again, Coal is about half the generation in the United States and if that recedes, and it is displaced -- replaced, I should say -- by natural gas, then continental demand is going to go up. And if demand goes up, the other side will just be supply. But, you know, and that sets the price.

COMMISSIONER BOYD: Demand for gas goes up, the price of gas goes up, the value of IGCC or something like that could hold.

MR. PUGLIA: Right, and the price differentials in LNG are going to continue to leak supply overseas, too, if we continue to see $2 to $3 differentials in LNG with other pricing points in the world, and that Kitimat is going to be the start.

COMMISSIONER BOYD: Yes, sir. We have finally got someone from the audience over here.

MR. OSTEN: Hi. Jim Osten, HIS Global Insight. First off, thank you for your presentation. I think the number one issue here today was addressed in your presentation, is what happens to gas demand long-term in the utility sector, which we have many answers. But just to comment on the modeling, when we model the reaction to the carbon policies, you can do it with a carbon tax, or you can do it with mandates, or you can do it sort of trial and error to get to the target. And I think a good question to go back for the models for your next position, is to what extent they just did a mandate, or they forced the answer on the model, or did they put in a carbon tax and calibrate --

MR. PUGLIA: They calibrate the tax, they did it then. Nobody did a tax, everyone used a cap.

MR. OSTEN: Right. When we analyzed the Boxer Bill and we put all the pieces in, we found that everything matched and you met the target. It was obvious, if you asked uses of models, if somebody had used the model to sort of design and integrate the policies to understand how to get to them, to the coal, so --

MR. PUGLIA: I think you probably understand that Congress avoided a tax and went with a cap because, as you know, and they were told, the tax gives you a certainty of cost, but if you look at a market where the information is not perfect, then you want to try to shoot for either certainty of cost, or certainty of productions, and the cap, as I think you know, will get you a lot more certainty of carbon reductions than will cost generators. That is their problem. They can worry about the costs themselves and I think that is what motivated the preference for legislation, ignoring taxes and going instead with caps.

MR. OSTEN: Good. Just one final comment. Some of these models, did you could get a chance to talk with the people who ran the models, find out if they have ever run them with a carbon tax, and get a sense of the responsiveness that the models have to the fact that could be --

MR. PUGLIA: That would be interesting, yeah.

MR. OSTEN: Thank you.

COMMISSIONER BOYD: Thank you. Anyone else? I keep forgetting to ask, what are you going to do about people on the Web, if they want to ask questions?

MS. KOROSEC: We are monitoring the chats to make sure if anyone has a question, so I will just remind folks on WebEx, if you do want to ask a question, make sure that you let the Coordinator know.

MR. TAVARES: Uh, thank you, Peter. By the way, there is going to be a presentation this afternoon by a specialist from Duke University, one of the studies that Peter just described. So our next speaker is Dale Nesbitt. He is very well known in the industry. He is going to talk about carbon regulation, renewables, electricity, and the consequences to gas markets. Now, Dr. Nesbitt holds a Bachelor of Science degree in the Engineering Science from the University of Nevada. He also holds a Masters degree in Mechanical Engineering from Stanford, and a Masters and PhD degree in Engineering Economics from Stanford University. Dr. Nesbitt is known in the energy industry for his market analysis, including the North American Regional Gas Model, the World Gas Trade Model, the World Oil Model, the Western European Gas Model, the North American Regional Electricity Model, the North American Emissions Model, and the North American Coal Model, and other models. The market modeling methods developed by Dr. Nesbitt have been used for most of North America and the World energy companies in oil, gas, electricity, and coal, and emissions business. So, Dr. Nesbitt.

COMMISSIONER BOYD: Welcome, Dr. Nesbitt. If Commissioner Byron were here, he would feel real good as a Stanford graduate and [inaudible] [85:36] U.C. Berkeley graduate.

DR. NESBITT: Absolutely. Very good to see you again. Good to see the Commission and the audience. And I do want to say thank you for that introduction, Ruben. I do want to announce that, when I came from the University of Nevada to California, I dropped the average IQ of both states.

I am going to talk a little bit today, I do not have a lot of time. Thank you very much for the opportunity to talk to you. I remember last time I was here, I talked about world gas and North American gas, talked a little bit about that tangentially. The topic today is carbon, and you have also got to talk about renewables, RPS and RECs, as will. And what does that mean for natural gas demand? I remember the last IEPR, there was a big debate whether, if you have more renewables entering the system, what does that do to natural gas demand? And we had the right answer back then and I think we can justify it a little better now. But I will talk a little bit -- a lot, actually -- about emission of SO_x, NO_x, Mercury, and CO_x -- I usually say "socks," that means SO_2 -- I will talk a little about renewables, talk a lot about what the incremental impact of CO_2 regulation, particularly cap and trade regulations, can be. And thanks to Jim Osten, I think he lay out correctly, you really can not model CO_2 unless you model it endogenously. Everybody please raise their right hand and repeat after me: The price of CO_2 depends on the price of fuels, and the price of fuels depends on the price of CO_2. You cannot run CO_2 scenarios -- you cannot do it because you get fundamentally inconsistent economically valueless kinds of things. We have seen this in sulfates, we have seen this in NO_x for many years. When the price of gas changes, hello? SO_2 price changes. This is not an accident. These prices are intertwined. And we are going to talk a lot about that today. Hey, this is like my computer back home.

Okay, how does environmental regulation work? It is worth talking about this generically, just for a minute, and then we will talk about some results. And in particular, how does the electric sector -- and I will talk a little about the oil sector if you like -- respond to CO_2 cap and trade or tax regulation? What is going to happen over there? And how is that going to affect gas demand, and gas burn, and gas price? The most important reg question, everybody wants to know that. If the price of CO_2 is endogenized in the system, what is it going to be? Is it going to be $200 a ton? Is it going to be $7 a ton, or is it going to be somewhere between? Or, in the spirit of uncertainty, is there a uniform probability distribution between zero and infinity? That is what a lot of people think.

Electricity in the good old days, everything was a label problem. Who was it that said that all politics are local? Well, all electricity was local until now. Everybody dispatched their own systems, they built their own plant, the met their own need. If there was intercourse between the systems, it was on the transmission system. There was a pooling agreement. That was it. That world has changed. Oh, and back in those days, there was such a thing as dispatch. Everybody raise your hand if you think dispatch is a concept that means anything today? Notice my hand is down? People run their plants when they want to. They do not run them when they do not want to. There is no dispatch anymore. If there was dispatch when we had centralized, we would have had monopolies. Now days, with the advent of SO_x, NO_x, mercury, and CO_2 regulation, you cannot just look at each plant locally, you have to understand the thermodynamics, or you need to study the heat rates like we always did, but you have to know -- and thank God people have accounted for this -- the amount of SO_2, the amount of NO_x, the amount of Mercury, and the amount of CO_2 a plant puts out, per Btu of fuel or per megawatt hour. If you ignore that and just look at the thermodynamics, then we are on the left on this diagram, or the various plants types. The left-most bar is gas in both groups. And all the right-most bars are different kinds of coal. And we all know, if we look at gas prices where they are today and coal prices where they are today, coal plants are cheaper than gas plants on a variable cost basis. Like this is rocket science? You are not going to get the statue in Stockholm or the Nobel Prize for knowing that. However, if you start to price these various flows in SO_x, NO_x, Mercury, and CO_2, at some different levels, and I would use some levels that we have seen historically, you will see quite a different picture begin to emerge. And this is the whole point of CO_2, regulation. Raise your right hand and repeat after me: the point of CO_2 regulation is to drive coal to the margin; that is the point of it. Does it, though? That is also the point of SO_x regulation, it is also the point of NO_x regulation, and it is also the point of Mercury regulation.

COMMISSIONER BOYD: Consequence or point?

DR. NESBITT: Point. I think it is the point. We know that when you burn a ton of coal -- what is coal, aside from the Periodic Table of the Elements than the ash? It is pure C. What is Methane? CH_4. What is nuclear? This is the Periodic Table of the Elements shown in fuel rods. What are renewables? It is nothing. We know that the point of this regulation, whether it is a consequence, it is the point, I believe, is to drive coal over the margin because that is the only way you can free up a CO_2 allowance. So we look at what happens at historical price levels on the left for plants that are not retrofit with an SCR, Selective Catalytic Reduction removed NO_x or limestone scrubbing to remove sulfates, or any activated carbon, or similar things to remove Mercury. If we price and endogenize those pollutants, we get very high generation costs. And the full costs are much higher than the gas plant costs. If you go over to the right side, where in the last 10 or 12 years when we have been retrofitting coal units and some gas units to get rid of So_x, No_x, and Mercury, we still have that big green area, the big green area is carbon. It is very hard to get carbon out of the effluent in coal plants, it is very hard to get it out of the effluent at a gas plant. Okay? One of the other very important points, information that raises your point, emissions cost can easily double or triple generation costs. The little secret is they must or they do not get the cap. The price of carbon must double or triple coal generation costs, or you do not ramp back the operation of the coins if you do not hit the carbon cap. This is not just monopoly money. To think that the acid rain program, or the No_x control program uses monopoly money to play with, no, it is not monopoly money, it is real money. Real money. One of the other very very important insights is for SO_2, No_x, and Mercury; we do have the technology because they are chemically active elements. So_x is chemically active, that is why it makes sulfuric acid. No_x is chemically active. Mercury is chemically active. That is why they hurt people and property. You can remove those things chemically very easily. We are as a species smart enough to do that, but CO_2 is a little tougher. It is extremely inert. And I think the comment that CO_2 is going to change the world was right, it is a chemically inert thing -- it is like water. It is about as inert as you can get chemically. It is very very hard chemically to get CO_2 out of anything, except for Coca Cola, you just drink it. So how do these regulations work? Well, the 18.5 thousand power plants in the United States, 18.5 thousand, can you imagine that? This big old demand curve for emissions allows this, doesn't it? And as those plants run, they generate a demand for emission allowances. Those emissions allowances are aggregated into a supply function under something like Waxman-Markey, or under its predecessors that were talked about. And with the EPA, or by law does, is they set a supply function for these emissions allowances, don't they? That is what the cap under Waxman-Markey is, it is supply function for allowances and we will talk about how they distribute them in a minute. The market is a demand function. And what happens when you have a supply function and a demand function? We cross each other. Let's hope they cross each other; and where they cross each other, there is a lot of the insight there. We want to know where the CO_2 supply function and the CO_2 demand function cross each other. And I will offer you some thoughts on that. I do not think it is all that hard.

So now days, this is the picture I want you to put on your cocktail napkin and talk to your significant other or anybody who will listen to you, because this is very important. If we look at these emissions allowances, some of which are traded, some of which are taxed, down at the bottom there is a supply and a demand function sitting down there. There is also a supply and a demand function regionally interconnected for all the electricity in the United States. We here in California, we are connected to Pittsburgh Steelers fans. We are connected to Atlanta Falcons fans, because we have all got a bid for CO_2

allowances. We have all got our bids for NO_x allowances. We have all got a bid for SO_x allowances. So what we have done by putting a CO_2, a Waxman-Markey type thing in, if indeed it does come to pass that we can theorize whether that is going to happen, it binds all the generators in the U.S. together because the point of it is to find the marginal plant and push it out, and thereby hit the aggregate cap, whatever that is for CO_2, whatever it turns out to be by law or by regulation -- so important. The price of electricity depends on the price of coal -- excuse me, the price of fuels -- and allowances, and the price of allowances depends on all the prices of all the fuels, doesn't it? So we have built that model and we have slipped it to the World Gas Trade Model, we have run it a few times. So we have all 18.5 thousand power plants in there with their little thermal and stoitimetric* [96:21] balances, and we just say, you know, let's look at them altogether and see what we get out of it, see if we can get any insight. And you be the judge of that. We have been doing this in the industry for quite a bit. It is kind of interesting what industry wants to know right now, very interesting. If you go into the Eastern connect, what is industry thinking right now? They would love to have local carbon and SO_x and NO_x and Mercury control. They are local on SO_x, NO_x, and Mercury right now. Why is that? Because the Corps vacated CARE.

There is no federal SO_x or NO_x or Mercury regulation right now. Big fight, or are we going to have best available control technology, which is local? Or are we going to go back to a federal or a regional cap? This is a very very interesting question. The industry really worries about that. What do the utilities want? Local control. They do not want federal control, they do not like it; that is why they filed suit against CARE. What does the federal government want? Federal control. So that one is going to play out. It is going to have some interesting consequences.

Okay, so what is this price of CO_2 likely to be? The answer will be given at the talk. Unfortunately, this is not the one with the results in it. Do we have any other slideshow? No. Answer will be given at the talk and if the slides have been properly cued up, you would have your answer by now. Well, we will talk a little bit. What I have done is I have run three scenarios here, one scenario was no CO_2 regulation at all, but continue SO_x, NO_x and Mercury regulation. The other one, I have run Waxman-Markey with the CO_2 offsets that are envisioned in the Bill. A third one I have run is Waxman-Markey with no CO_2 offsets in the Bill. And as you guys know, people are really debating whether or not we ought to have CO_2 offsets. And the CO_2 offsets that are presently printed in the Bill are big. If you look at that Bill, the way it is right now, if you look at the year 2005 as your reference year, and you allow the CO_2 offsets, by 2030 the cap is only down about 15 percent if you allow these offsets. If you do not allow these offsets, the cap is down by 58 percent. These offsets are huge in these Bills. And I always joke, this is the plant, the banana trees in the tropics kind of offsets. And the theory goes that if CO_2 is easy to sequester -- just talk? Talk systematically or talk randomly -- it is like walking and chewing gum. I made it hard for you, didn't I? So if you allow these offsets -- we will get back to that -- if you allow these offsets, you only have to drop carbon by 15 percent from its 2005 levels out to 2030, that is not a whole lot. You certainly can accomplish that kind of thing with or without a model by substitution of gas for coal in a common fleet. If he puts PowerPoint just up, and then he does a share on the WebEx, it will come. I will make one other point, too, and I will not waste your time with the slide here, and the other point has to do with, so how do these carbon emissions allowances get put into circulation. Like anything else, I always just tell a joke, there are three kinds of people in this world, those that understand math and those that do not, well, there are two ways to do this and there is sort of a continuum between it, one way to put these CO_2 allowances into circulation is the way we always did with the SO_2 allowances, drop in the mail, lick the envelope, and mail them out to the utilities for free -- that is called the allocation method, or the assignment method. Mail them out. What happens when you mail these emissions allowances out to the various utility companies? What do they do? AEP is a classic example, they have been in the press a lot. They get $4.5 billion worth of emissions allowances in the mail in the form of SO_2 and NO_x credits. What do they do with those?

MEMBER OF AUDIENCE: Sell them?

DR. NESBITT: No. It is very interesting what they do with them, and this is what the fight is. What they do is they embed them in their dispatch decision, and then they are forced to put them on their books and reduce rates to rate payers by $4.5 billion. That is an easy calculation to make. The rate payers say, "Can I have a look at the envelope he opened on January 1st? Oh, $4.5 billion, okay, you are going to reduce rates by $4.5 billion." Period de Mundo* [101:57]. Okay? So what happens is your wholesale prices in the AEP service territory are significantly affected by the emissions allowance, but your retail prices are discounted because the regulators force you to pass what you got in the mail back to your rate payers. It is very important, though, to state that the wholesale prices are significantly elevated by these emissions allowances. You have to dispatch more gas and less coal because of these allowances. Okay? Now, who thinks that, because you are handing these emissions allowance costs to $4.5 billion back to your rate payers, the answer is Congress? Who thinks that the net is zero under an allocation scheme? Everybody is saying it is zero -- it ain't zero because you changed the way the plants are dispatched. But then you rebate the value of the allowances back to your rate payers. What is the other method? It is what RGGI is doing, the Regional Greenhouse Gas Initiative in the Northeast. I believe WGI is talking about this, too, and this is what is called auction. You do not care if you owe nobody nothing. What you do is you put them in a central repository, the allowances, and you make the generators buy them, every single one that they need to surrender at the end of the year, they have to buy. And a market price is established that way. If you are an AEP, what does that do to you? You do not get anything free in the mail now, you have to pay for it. So do you have anything to hand over to your rate payers? Do you have anything to hand over to your rate payers? No. What do you have to do as a utility company? You must transfer the $4.5 billion that you had to pay over to your rate payers in the form of a higher price, so you embed the externality in prices at retail. Does everybody understand that? Under an assignment method, you do not embed the emissions cost in your retail price, so you over-consume, but you still do drive up the costs because you have changed the dispatch of your plants. You have changed the operation of your plants. However, in the auction method, you have totally embedded the carbon cost all the way through the stress supply chain, all the way out to retailer, and you force, in the lexicon of economists, efficient decisions.

Now, it is very important -- I want you guys, when you read the trade press, go look at the natural gas daily yesterday, they said that the big debate in Congress was, "Well, you know, if there are allocations, this is a waste of time. Waxman-Markey is not going to work." This is wrong. It is not sort of wrong -- it is dead wrong. It is dead wrong. Whether you assign these and give them away, or whether you option them, you will affect plant dispatch because you cannot fit the cap until and unless you affect plant dispatch. Does everybody understand why? And the other thing is you have to add any new capacity of any kind to reduce carbon output. Do you have to? That is a darn good question. The answer is no. Why not? Because without CO_2 controls, what happens? You run all your coal plants, and then you run your gas plants at the margin, just like the gentleman suggested this morning. What do you do if you have a CO_2 cap? You run all your gas plants and coals at the margin. You cannot cycle coal funds, c'mon, Nesbitt, this is thermodynamically impossible. Want a bet? Phone Germany. Anybody speak German? Why do you think the Germans pulled out of the EU carbon trade? Why do you think? They were dispatching their coal plants. They were cycling these mammoth Volkswagen coal plants. It is very clear what happens when you put a CO_2 cap on -- we are not talking about whether you should -- you shift your gas plants infra marginal, thereby raising your base-load generation costs, and you shift your coal plants to the margin. You have to. And you do not have to build an iota of new capacity to get there. Now, you will build an iota of new capacity -- very important.

Okay, let's talk a little bit about the results that came out of this model. I think they are insightful and, since I am giving the talk, it is my opinion that matters -- no, I am kidding. If you do not do anything, this is a picture in a national '66 region bazillion note electric model, with 18,000 and a half generators in it. How much coal do you burn by type? And keep in mind, I have continuation of CARE-like regulation in here, so SO_x is regulated, NO_x is regulated, Mercury is regulated, CO_2 is not. I want to look at the margin at CO_2 regulation because the charter is what does CO_2 regulation really do at the margin and how is it going to affect things like asthma.

You burn quite a bit of coal. We are burning about 25 quads of coal a day minus a little, we do not know what we are burning today. We have got a little recession on our hands. Power gen is down 10 percent. There is a forecast that I did not make, and no one else did. Power gen is way lower than we thought it was going to be this year. Anyway, and you burn some sub-Bituminous coal -- you are still burning a lot of this Bituminous stuff in the Inter-Eastern connect. That is interesting. What fraction of the U.S. generation fleet is coal? Do you know? A little more than half -- it is about 450 gigawatts of coal for an 850 gigawatt peak. That is a lot of coal. That is a lot of coal. Okay, what portion of California's input is coal? It is pretty high, actually. We do not like to think so, but LADWP brings a little bit of coal in, don't they? That is why we have that AB 32 structured the way it is, it has to do coal accounting on imports. So we actually -- we do not have coal in the state, but we are pretty dependent on coal. Okay, next. So this is what happens if we do not do anything. Coal goes up over the next -- and I am sorry, the horizontal axis goes up to 2030 -- this is how much coal we burn in the West -- we do not burn too much more in the near term, we have got quite a bit of capacity here, but when you go to the long-term, you have to start adding coal or you will start adding coal if you do not have coal controls.

Now, here is a little interesting insight for you on coal. If you do not have CO_2 regulation, do you think we are going to build a lot of new coal plants? Who thinks we are? Notice my hand is not up? Why not? Have any of you kind of gone to your little Office Depot catalogue and checked out the cost of a coal plant lately? It is $3,000 a kilowatt. So Eric Markal from Puget, I will never forget this, about four years ago he stood up and he was teasing me, he was at the conference, and he said, "Well, there were about a 4,500 megawatt utility, we're thinking about building 1,000 megawatt coal plant, so that will increase our capacity by, what, 15 percent, $3 billion. Hey, Nesbitt, you want to take that to our Board? We're worth $3 billion. That is our total market cap. Nesbitt, you want to take that to the Board? And if you do, you'll never see their faces again." These babies are huge relative to the companies that we are asking to invest in them. Coal is not going to happen on a pure economic basis. CapEx matters. So gas burn is going up anyway, it has to. How about nukes? What is the latest cost of a nuclear power plant? I know the latest one I have seen. $9 billion Somalians* [110:18] for a thousand megawatt plant. Now, that is not even in the Office Depot catalogue, it is so expensive -- $9 billion. What utilities in this country can support the CWP risk, Construction Work in Progress, if it has got a $9 billion power plant? Not too many. That is very interesting. The CapEx on these base load plants has gone off the charts. Now, we can debate and, certainly in a forecasting sense, we must debate whether or not they are going to come back to earth. But right now, they are in infinity minus just a little bit.

MEMBER OF AUDIENCE: There are some in the pipeline, nuclear projects.

DR. NESBITT: Seven billion dollar nuclear project in the pipeline in Entergy. If you were at Entergy, would you build it if your market cap was $16 billion?

MEMBER OF AUDIENCE: I would build coal.

DR. NESBITT: If you are Entergy, there is another -- we will talk about Entergy in a minute. Next slide, I am sorry. So here is gas consumption in the WECC, or total U.S., and this is very interesting. If you have no CO_2 controls, how can gas consumption stay low? Anybody tell me a scenario where gas consumption can stay low for power gen? And do not say renewables.

MEMBER OF AUDIENCE: And efficiency.

DR. NESBITT: Maybe, but do not say renewables. Why? What do renewables compete with? Commissioner Boyd, the answer has not changed -- they compete with coal, they do not compete with gas. That is the point. That is the beauty of renewables, they compete with coal. Next. And that is the WECC, a little bit of reduction in gas consumption and it goes up in the long term. Next. We will come back to that. There is the gas prices that come out of my gas model, those things are beautiful, you can make a book on that. Next. And the basis differentials -- next slide, please -- oh, I did not put them in here -- next slide, please. This just tells you how great the model is, everybody knows that. Next slide. What is -- the red line is Henry Hub; I have subtracted all those other lines through Henry Hub and what do you see? Everything goes up compared to Henry Hub. I hate to say this in California, I am a life long Californian since I dropped the IQ of both states -- California is going to be the most expensive gas in the world. Pacific Northwest is going to be the most expensive gas in the world long-term -- has to be. I hate it when that happens, don't you? Where is our supplies? Ain't too close, are they? Where is our demands? They are big. We care about clean air. We have to care about clean air in California because we have an intrinsically dirty air in our air basins. Commissioner Boyd was right, the reason we have clean air is, 30 years ago, we decided we wanted it and we spent a lot of money getting it. I do not see that turning around. I like to look at the San Gabriel Mountains, even though I do not like to go to L.A. too often. It is very interesting. So the basis differentials are climbing relative to Henry Hub. Why is that? What is the low water point for gas price in the U.S.? The supplies for LNG comes in the long-term. Where is the shale? Pretty darn close to Henry Hub economically. Fayetteville, Bossier, Barnett, Marcellus, they are connected to Henry Hub. They are in the Mid-Continent, they are in the Eastern Interconnect, they are in Texas, to answer the questions earlier on. Next.

Power prices. What is going to happen to power prices even if you do not have carbon regulation? They have got to go up. Why? You have got to build some capacity. We have got some power plants that are going to leave the system -- 60-year-old power plants are not too safe. You do not want to go up on the top of that water cooler when they turn on the pump because it might pull it down. Next.

Okay, now, let's look at Waxman-Markey, it is very interesting. We want to overlay Waxman-Markey with offsets on this, so next. Here is what happens to natural gas. This is an integrated model and it is the lower line. In the near term, if you have CO_2 with offsets, you get about a $.30 higher gas price at Henry Hub. But then the difference at Henry Hub drops. Why is that? You are going to have a lot higher gas consumption here. You are going to have a lot higher LNG imports, too. And you are going to have a lot higher shale production. If we have the gas, we will use it, wouldn't you think? Next.

COMMISSIONER BOYD: Is that LNG in California, also?

DR. NESBITT: My own views? You will see LNG in Oregon and you will see LNG at Costa Azul. Yeah. Commissioner Boyd, we are going to be the highest gas price in the world, yeah.

COMMISSIONER BOYD: I will be retiring and moving to Nevada first.

DR. NESBITT: We do not need it up there, we just burn things. Next. Now, if we have the offset -- no, go back one, please -- this is very interesting. If we have the Waxman-Markey type cap, which is not that severe with offsets, we get a dramatic reduction in coal burn. So it is true. When you have a CO_2 cap, you will reduce coal. It is the biggest producer of CO_2. It has to leave the system in order to comply with the cap -- it has to. You cannot run the coal fleet we have today and hit the cap because Waxman and Markey and their staff are kind of smart. They kind of looked at how much running the coal fleet would imply, and they dropped it. That is the whole point of CO_2 regulation is to make sure that the aggregate amount of CO_2 goes down. Next. CO_2 in the WECC. We see a lot of reduction in CO_2 in the WECC, and you see a big discontinuity in the year 2012. One of the other things you see in the Waxman-Markey bill, and I have not emphasized it here, is it calls for a lot more renewables to come in to the system a lot earlier on, like in 2012, and we have simulated that here. So the RPS is accelerated under the Waxman-Markey Bill relative to the no control Bill. And I think that is a reasonable thing to assume -- next -- since they say they are going to do it.

Man oh man, does gas consumption go up. We are burning about six quads right now? You are looking at a lot of increase in natural gas in the United States if you have that. That is what it takes to hit the cap. Next. And in the WECC, too. Notice the acceleration does not start for three or four years, but it does accelerate. Next. Here is the price that comes out of the model endogenously. Jim, you are right. Out of my model, it comes out endogenously, none of the exogenous stuff. And what is the price of carbon? What does it take to clear this market? And the answer is about $30 a ton until 2018, and then it has to get to about $80 a ton after that. You get the low hanging fruit early, but there ain't no low hanging fruit long-term. Next. Okay, now let's do an even more constraints scenario, let's pull off the offsets so that we have to get a 58 percent reduction in CO_2 output by 2030. The old Leiberman-Warner Bill was like this. Next. You do not get that much difference in price. This is a very interesting insight. Everybody raise your right hand and repeat after me: The Earth is an Éclair, and almost everywhere you drill, there is natural gas. It just does not happen to be in North America. We laugh about that, but if we look around the world, there is a lot of methane out there and it is very close to the water in a lot of places. In places like Russia, it is not, but they are pretty close to Europe. So you do not get a huge pop in gas price, if you believe that, when you increase gas demand. That is a very profound point. We should debate that. There is a lot of gas in the world pretty darn close to the water. Next. Next. We will pass the price difference. And you get an even more precipitous coal drop-off if you eliminate the offsets. Of course you do. That is the whole point. Next. And you get a much more precipitous coal drop-off in the WECC. Next. And you get an even bigger pop in North American natural gas consumption. Next. And keep in mind, one of the things I have here is I have a federal RPS, which is -- it is not the strictest RPS, but it is pretty strict. It gets to 20 percent on a megawatt hour basis, what, in 10 years. That is a lot of renewables. Next. Gas consumption has to increase markedly with or without offsets. There is really no alternative. The benefits of gas and renewables are strongly synergistic, they do go hand in hand, and we will talk about this in the risks section. Why? Renewables are intermittent. What are you going to back renewables up with? Nuclear? No. Coal? No, you cannot buy the offsets.

Oil? Right. It is gas. It is black start gas. Renewables and gas go hand in hand. It is a good thing, they are both clean. Next. And how high -- as the rate of carbon price goes up, it goes up another ten bucks in the intermediate term, and then it goes up another five bucks in the long-term, ninety bucks a ton in the long-term. Is this reasonable? I think I can convince you that it is. Next. Okay, anybody want to do some stoichiometry? Everybody knows what it is? One more, quick. We are going to go really fast hear. I am running thin on time. Next. Okay, if you had yourself a gas plan and you pay $7 for gas that was at 10,000 heat rate plant, $3.00 per megawatt hour operating cost, you would pay $73.00 if there were no environmental costs; if you had a coal steam turbine, you would pay $2.50 for the goals at a 10,000 heat rate unit, $9 of operating costs, that is $34. Next. We put the stoichiometry on it, okay, if $73.00, we know in the top line there is about 117 pounds of CO_2 per million Btu of gas, that is stoichiometry right off the EIA website. We know in the lower one there is about 205 pounds of CO_2 per million Btu of coal, that is just stoichiometry. With 10,000 heat rate units, these little equations here tell you what the dispatch costs of your unit is as a function of your carbon price. Go to the next chart. They cross. What do you have to do if you are going to hit a carbon cap? It must be the case that the carbon price has to rise to the point where the coal plant will not dispatch, and the gas plant will, i.e., the carbon price has to rise to the crossover point. The crossover point is $88 a ton. That is what it takes if all you had doing the work for you was CO_2, that is what it would take to push a coal plant out of the stack and pull a gas plan into the stack. Now, you have SO_X, NO_X, and Mercury helping you out, and that is why you are only getting $40 to $50 a ton. These numbers are very reasonable. You are looking at $30-$50 a ton under Waxman-Markey. Next.

What if gas price goes to $8.50? You are looking at $120 a ton. Very sensitive to gas price. And if you have a cap, it does not matter how gas price -- how high gas price goes. The CO_2 price must rise until you get the trade-off, otherwise you do not hit the cap. So the carbon price is a function of the gas price. Next. What if gas price drops? Next. Gas price drops to $5.50, we are at $50 a ton carbon price. God, that makes you feel pretty good, somewhere between $50 and $100 a ton, depending on SO_x, NO_x, and Mercury, that is what we are looking at. That is what we are looking at. That is what it takes to push coal to the margin. Next. Well, let's talk about this, go back. Who among you thinks it is a smart idea -- and my hands are both down -- to run scenarios for CO_2 price? This is the biggest waste of time you can do because the CO_2 price is an endogenous function of the fuel cost, not exogenous. You cannot do that. Boy, that shut down my presentation, that statement, didn't it? Next. They are all wrong. Why run scenarios you know are wrong? Here is a little example I always give my customers. Let's do three Physics experiments. We will use the speed of light of 90 miles an hour, 900 miles an hour, and 9 million miles an hour. Let's do that. Whoa, what's the matter with you guys? Three speeds of light and I have got three scenarios. What's the matter with you guys? You do not want to be doing that? Next. Safety valve just a tax. Next.

Renewables are very interesting and I will talk -- how much time do I have left?

MR. TAVERES: About 20 minutes.

DR. NESBITT: Twenty minutes left. Oh, I have got a lot to say, now. Kidding. Renewables are very interesting because they interact very directly with the CO_2 tax. When we think about what a CO_2 tax does, or a CO_2 cap does, it raises the wholesale and retail price of electricity as it internalizes the otherwise external cost of carbon, right? What does that do for renewables, or the value of renewable energy credits? It renders them more economically competitive, doesn't it? Now, that is interesting. It is very interesting. So if you say, man, if we are going to have $100 per ton of CO_2 tax, we might not have to subsidize renewables. And the value of renewable energy credits has got to drop. So important. So your renewables and your renewable energy credits have to be endogenous in your model. God, I hate it when that happens -- I actually like it when that happens. Next. Let's talk about that.

So what have we done with renewables? We cannot talk about carbon without renewables. Or renewables is the number of renewables that are designated as qualified vis a v s the credit. Some debate whether hydroelectric is qualified, but certainly the big qualifying types of renewables will be wind, the main category, solar of various types, biomass of various types, geothermal of various types, and others. There are kind of five that I carry in my mind. I want to talk a little about wind and I want to talk a little about solar because they are important ones as part of these impending RECS and these impending and perhaps renewable portfolio standards, and we have not even gotten to conservation yet. Next. A lot of states now have their own RPS standards, I do not know that anybody is trading RECS very actively, other than voluntarily right now, I could be wrong. But the states are mandating, we would like to have X amount of megawatts or megawatt hours, generally megawatt hours, generated by renewables, and we would like to have that be a given fraction of the total number of megawatt hours that we generate. This is typically the way these are put together. This is about a year old, but these are the credits that were out there by about a year ago. Next. Let's talk a little bit about how you get there with the wind component of that portfolio. It is very very interest, wind. Next.

Now what do we know about wind? We know it ruins your golf game -- not my golf game, actually it does not affect it very much, the score, at least. We know around the world, what is the best load factor on a wind turbine? 40. You know, if you go up to the Golden Gate Bridge, does the wind always blow out there? About 35 percent of the time, you just happened to be there when it is blowing. Very interesting. So they do nothing 70 percent of the time. It is a difficult technology. So what we did is we decided to go out and gather wind patterns everywhere around the Continent. The other thing we found, and you have seen this especially in California in the last summer, the generation pattern is fairly random, but there is one exception. What is the one exception? It is the one you do not want to hear, right? Wind does not blow on the hottest day. It actually does blow. It blows up and down. We have temperature inversions on the hottest day. Texas found this in spades last summer, and it does get hot in Texas. No wind. Remember the heat storm we had in California a summer and a half ago, it got to 115°? Utilization on the wind turbines that day was 3 percent. We know. It is not a political statement, it is just a weatherological statement. We have got to do something about that. And what is it that we have to do? We have to back up the capacity. We want the energy that the wind turbines general because it is clean, because we paid for it. But unfortunately, we do not get them at time of peak. God, I hate it when that happens. Next.

Okay, so how do you model these things? I know how everybody models it and I get weary of it, I have to reach for the Rolaids. If you have got a megawatt of wind turbine and it runs 30 percent of the time, there is a red line 30 percent of the time to the top of that chart, and there is no red line 70 percent of the time to the top of that chart. A lot of people say, well, on average, we are going to get .3 megawatts. No you ain't. It is more systematic than that. You cannot really de-rate these wind turbines and model them. You have to model the stochastic. Next. One way to do that is look at these generation patterns as you observe chronological patterns by hour, really, and run them out across a month and then you want to map them in to the time when the loads actually occur. And that makes a lot of sense, doesn't it? So you say, all right, the wind is blowing various hours in the month of

January, I am going to map those into the demands for January, and they are blowing various hours in February, I am going to map them into the February demands, March, April, well, if I do that, I can generate what I like to call a wind duration generation curve. You ought to do that if you are going to get the impact of wind right. And the wind generation duration curve in the summer looks kind of like that green block over there. You do not get much wind at the time of peak, you get quite a bit of time of off-peak, and you want it. Everybody see why this is? And all the wind that you put in has a different wind generation duration curve; you need to stick that into your model and offset the load that your thermal clients are going to be serving during those hours because that is the function of renewables, is to provide energy on a real time basis when it occurs, and then the thermal units have to make up the difference, the whole point, you are just replacing thermal units. The thermal units go to the margin. Next.

And so the wind duration generation curve for each month that we have put this together in the 66 regions, and we have posited a wind piece of the portfolio and stuck it into the model. And what happens when you do that? It is very interesting. Next. Next. You will take -- and this is a monthly load duration curve, that will be the red curve behind, and the discrete version of that is the blue curve.

You are going to know off some load because your wind is going to be contributing to load, to serving load, to different degrees at different points in time, so you end up with a grey curve for your thermal plants to serve. Next. One other thing that you see with wind, I will not go too much farther, you see this everywhere in the United States, you see it everywhere in Europe, if you look at the diurnal pattern of wind, wind velocity is lowest at 2:00 in the afternoon and it is highest in the middle of the night. You do not know that because you are sleeping, unless you are working graveyard like I used to do as a kid and saw it. And so you have to have the diurnal pattern in there, too. You do not really want this during the summer. But what you see when you put wind into your system is that your load duration curve, if you will, in a given month was red without wind, it is black with wind. That is not bad. You get a more peaky demand that your thermal generators have to serve. What does that mean? Less coal. More what? More gas. How can it be otherwise? You have got a back-up capacity -- what does it do to the value of capacity? It raises it. You need that peak-load capacity big time. You need thermal capacity that can come on at time of peak, when it is 115° here in Sacramento. So you are getting the energy contribution from your wind, you are tending to get it at time of off-peak during peak months, but you are getting it. Next.

Solar. This is a little better news. Solar costs you, what? Five times what wind costs to install? But solar energy is correlated pretty strongly with time and peak. I do not know about you guys, but when it is 115° here and I look up, I generally see the sun. It is true in Texas, it is true in California, you have a nice correlation between solar PV and solar central station with peak. That is an interesting little property. Next. So if you go out and look, you have to think seasonally. I do not know about you guys, but where I live, when I go out in July, the sun is a lot hotter than when I go out in January. So you have solar insulation curves that vary by month -- we know what those are, this is not political, this is physical, you can go out and measure those things. And you have to do that and you have to generate -- next page, next, please, sorry -- a solar generation duration curve. Now, these are interesting. These tend to be much more strongly correlated with the need at time of peak. They tend to decrease the value of capacity, they tend to contribute at time of peak during the peak month. During the off-peak months, they still tend to contribute at time of peak. Hey, what the heck? So when you craft a renewables portfolio and stick it into the system, this is the kind of contribution you get by hour, by month. Next. So these are embedded into those previous results that I showed you. What does this do for gas? It is going to help, right? Unless you have thunderstorms. They get those in Texas, right, Ken? They get lots of those, and they happen 2:00 or 3:00 in the afternoon when it is 250,000° Fahrenheit. It is like the center of the sun. So you need back-up because of the stochastic of sun. They actually do help gas. You need to have black star capability just in case you have localized thunderstorms, cloudiness, blah, blah, blah, that tends to cut your solar insulation curve at time of peak. Next.

Biomass is an interesting one. Does Biomass run 24/7 360, 58760? Where I was born, I grew up right next to a meat packing plant, whew, man, we had biomass 365. But you know, the alfalfa crop kind of came in, in the summer, and the farmers were down at the bar all winter. Biomass loads and biomass contribution tends to be seasonal. And so they are a lot like hydro guys. They have got to decide when to burn the carbonaceous material to make energy. So they are kind of quasi-peakers, as well, biomass is, energy limited typically. Okay? The generations do have some degree of flexibility to dispatch those plants into the peak hours and they will, they do, these are not big plants. Okay, and when you go survey where the biomass is and so forth, you can find, you know, you might generate for 180 days and then the other 180 days you are down with the farmers. Okay? Next.

Geothermal is very interesting. On a big bankruptcy case I did for Calpine on Geothermal, it was a big deal. Geothermal tends to be highly site specific, it tends to be base loaded, you have got to pump water down the hole because the water comes out of the hole and never goes back down, so you have got to replenish your resource. But it is more of a base load energy source, site limited, you have got to understand that, as well. Next. Why do you do all this? Because, as you are looking for your thermal plants or, more importantly, the profitabilities of your renewable plants, which are elevated in a CO_2 world, you are getting the retail price of electricity and you do not have to buy any credits of any type because you do not make anything Gronk-y. This matters to you a lot. You have to know when your megawatt hours are going on the grid and how much money you are going to get for them; if those megawatt hours are bid up in terms of price, you get the money. So the interplay between your renewable portfolio standard and your CO_2 pricing is very very very strong because your CO_2 pricing is going to elevate the price. Now, CO_2 pricing -- this is a little quiz question for you -- does it elevate the price more at time of peak, or time of off-peak? If you have CO_2 capping, do you see more price elevation at time of peak, or time of off-peak? Who votes for time of peak? You guys are not going to vote. Who votes for time of off-peak? When do you stop running your coal plants? It ain't at time of peak, you need all the megawatts, right? So when you start constraining the amount of carbon you can put out, when do your coal plants stop running? Easter Sunday, 2:00 a.m. That is when they do not run. July 17th, 2:00 p.m., they run. You have got to have them to meet the peak; the system is sized to meet the peak. That is why you do this, because this interplay of carbon and renewables really interact a lot. And they both interact to drive coal to the margin and elevate the gas burn. Next.

Tradable RECs. What are these crazy things? Who came up with this? Tradable RECs are an interesting idea, in fact, a great idea. And here is the way they work. If we look at the lower right, if we build a renewable -- a qualified renewable and generate a megawatt hour with it, it generates a megawatt hour of physical electricity and it generates a megawatt hour of paper, an allowance. That paper then goes over to the thermal generators. And suppose we say to the thermal generators, "You must have a quarter of a piece of paper for every megawatt hour you generate." And that is what this little example shows. "So we will force you to surrender .25 megawatt hours of RECs for every megawatt hour you generate." If you do that, you will have a 20 percent renewable portfolio standard. You must buy the piece of paper in order to generate thermally. That is the idea. And what does that do? That sets up a market for these RECs. These RECs are sold by the owner of the wind turbine, or they are sold by the owner of the solar energy pv, or whatever, into this exchange. And if the thermal generator wants to generate, he or she has to buy them. And there is a market established. The money goes back to the renewable generator, right? He or she, for that megawatt hour, gets money for that REC. There is a market established. It is an economically efficient way, on paper, to mandate the 20 percent renewable portfolio standard, and all you have to do is mandate at the level of the thermal plants how many RECs you need per megawatt hour of output. So it is not clear to me that, with CO_2 and/or tradable RECs, that you need deep subsidies for renewables. That is a really interesting -- we have not even talked about conservation, which is demand reduction. Next.

The last thing, I will leave you with a quiz question. Keep going about 20 slides deep. I will ask the question and then we will answer at the second. Keep going, more, more, more, until you get to the part about storage. Right there. I will ask the question and we will answer it later because I see the hook out here. I feel like an Oakland A's starter, pulled too early. No. If you had -- let's suppose that you could reach up into heaven and you could make a perfect capacitor, and what does a capacitor do? It charges and it discharges, perfectly, and it is free -- a perfect capacitor. What would that do? Oh, infinite capacity of perfect -- perfect electric storage. People are really spending the money to get this right now, I will tell you that. What would it do? Very interesting question. Everybody says, "Ah, man, it would be a boon to renewables, it would be a boon…." No, it would not. Go down. All the way to the very last slide, then I will turn it over to Jim. Keep going. This is natural gas. The perfect capacitor would eliminate the need for peaking. You would run base load and then you would dispatch your entire system through your capacitor. It would really hurt renewables because where would you put your capacitor if you were an entrepreneur? You would put it at end use, wouldn't you? You would want 100 percent load factor on your capacitor. You would not want a 30 percent load factor on your capacitor. This is natural gas -- last thing. Natural gas. And we do the same thing with crude oil, we do the same thing in products. We have a highly timed varying demand, that is the red curve, and what is the production of natural gas in the United States? Every single day of the year? It is 65 Bcf a day. The peak goes to 90, the off-peak goes to 45. This is what storage does. It allows you to run your facility's base load. This is not rocket science. Storage allows you to run your facilities base load. As I leave, I will tell you a story about this. This is something to keep in the back of your mind. Base load is gold. I grew up in a mining town. My dad was a -- he managed a mine. Every night he would come home and there was a company phone, it was a closed circuit company phone, and he would say, "You hear that sound, Dale? You hear that phone?" I would say, "No, dad, I don't hear the phone." He said, "Isn't that the most beautiful sound in the world? We are at 100 percent load factor, my friend. That is what I am paid to do." And if you just sit back and think what you want to do with capital that is invested in the energy system, you want 100 percent load factor operation. What is the quintessential 100 percent load factor thing? Crude oil refinery? That shale refinery, if it drops to 90 percent, he is a McDonald's employee. The load factor matters. That is it. I will end with that. Gas burn is going up.

MR. TAVARES: Are there any questions for Dale?

COMMISSIONER BOYD: I am speechless. But Dale and I agree that humor is needed in these sorry times once in a while. So thank you very much. Folks in the audience, questions? Comments? Challenges? Speechless.

MR. TAVARES: Thank you very much, Dale. Our next speaker is Mr. James A. Osten. He is a principal with IHSGlobal Insight. Mr. Osten has been a North American energy economist since 1973. He has been involved in numerous international consultant assignments in Europe, Latin America, Indonesia, and South Africa. He has been responsible for forecasts in publications covering natural gas and LNG. Some of the publications include *Modeling Natural Gas for North America,* and *Natural Gas Markets and the Long-Term U.S. Energy Outlook*. He has performed detailed pricing and marketing analysis for LNG terminals use in modeling data for pricing points, supply and demand, to illuminate market strategies. He developed Global Insight's gas prices forecasting and analysis system used in studies of pricing natural gas transportation, testimony on behalf of parkland expansions, and detailed analysis of fuel cost for major electric utilities. Mr. Osten?

MR. OSTEN: Thank you, Ruben. I think Dale ran over a little bit, leaving me last in line between you and lunch, so I will try to be succinct.

I am here representing some of my HIS colleagues. I have had the opportunity to have the same desk for the last little while and I had my Zip Code changed, my Area Code changed on my phone, my company name changed about five times on my business card, and now I am part of IHS, which is a great company. It also includes CERA, Cambridge Energy Research Associates. ISH, with a wealth of data on wells and petroleum information, and Global Insight is where, well, it was Herolds and James and a number of other companies. The first thing I want to do is tell you a little about a study that CERA did called "Rising to the Challenge," a multi-client study on the natural gas market. And then I want to give you a very quick tour of Global Insight's economic forecast, one comment about the world oil market, and then a bit about natural gas. Let me start off with "Rising to the Challenge." Do I control these slides or -- okay.

The California Connection -- I do want to summarize what "Rising to the Challenge" has said for California. This study was led by Robert Ineson, Sr., Director of North American Natural Gas. Now, using the IHS supply capabilities, the IHS has well-by-well data, representing nearly a million wells, data going back to 1859 -- I think that is Titusville -- production costs are analyzed for over 120 plays. If you look at the Rocky Mountains, for example, the Rocky Mountains is represented with 60 plays, 12 basins, and 7 sub-regions. And then the information on supply is integrated with the demand information in the GPCM, or Brooks model. There are over 4,847 nodes connecting the 118 supply regions and about 120 demand regions of well. Just a quick tour of the GPCM, its objective function is to maximize consumer producer surplus minus transportation and storage costs, so it is focused more on short-term fundamentals. It does put in capacity in an exogenous manner. For example, future California pipeline expansions, it does include the Ruby pipeline and expansions on Kern River. There is a seven-step process to all of this, which I am happy to talk to you about over lunch, but I wanted to show you a little of the output from the model. Parameters, play level parameters, reserves, the decline rates, significant wells, number of wells, some of the new plays. New plays are a very interesting area of research. We hear about the Haynesville, the Marcellus, and other areas where shale plays are expanding. Not much is known in terms of actual wells and actual production history, and much has to be surmised. You will hear a wide range of numbers about these shale plays, and I think IHS has a role in the future of trying to sort out the actual information from the guesses.

This slide, the illustration of play to region consolidation, you are looking at defining states, regions, basins, plays, different shrinkage numbers for each of these, different types of production, coal bed methane, associated gas, interesting plays, new ones that are developing, a way of getting that information. The new plays, a great deal of time was spent looking at the geology, equivalent geology, old plays that have similar geology, old plays that have had similar costs. Costs are done in the Que$or software that IHS has. Supply cost, of course, has to be associated with productive capacity to get to a supply curve, or an integrated supply analysis. That information is integrated within GPCM and adjusted to produce the study results. So this presentation was brought to you by the GPCM and IHS data. Enough with the commercial.

Rising to the Challenge, California Risks. I do want to focus on risks. I felt the main purpose of being here today, for me, is to talk a bit about risk and a bit about volatility. What we are saying for California is that California faces diversion of natural gas supplies to premium East Coast regions. It is going to be exacerbated by the decline in Canadian exports. The Rex East pipeline is example 1. And there is also Southeast demand growth, and that has implications for the dynamics of California. Within the North American market, most supply growth is west of the Mississippi. The demand growth is east of the Mississippi. And supply is being diverted away from California. But demand centers are around the coast, the supply centers are shifting from Gulf to the inland shale plays, and therefore the West to East flows are covering shorter distances as shale expands. You see a long list of pipelines being built from the shale regions, or LNG terminals, to Transco Station 85, as an example, and those are shorter pipelines than, say, Rex East. Our past expectation was that Rockies would lead production growth and that is switching towards more of the shale production growth and the essence of the future dynamics.

Within the producing regions, there is a competition for market share in consuming regions. And many, Alberta, Rocky Mountains, Mid-Continent, the shale regions, the Gulf Coast, there is a portion that goes East and a portion that goes West, and this is where some of the implications are for California. The Rocky Mountains look to the East. The demand centers with the premium prices are currently on the East Coast. The Rex East Pipeline is going to replace declining Canadian exports with Rocky Mountain gas. As I mentioned, the Ruby Pipeline, Kern River expansions will add some supply to the West. Generally, Rockies gas will flow eastward to the extent of pipeline capacity, with the residual supply serving the West. Canadian supply is declining. We do have in the forecast Canadian production falling, while demand rises with the oil sands. But the West Coast holds about 2-3 Bcf of supply, somewhat higher in the summer. Our net exports from Canada fall to 6.1 Bcf per day in 2010. I want to show you pictures that illustrate that change. The upper left-hand slide, you can see the flow to the East, and that is the total East, rising from pre-Rex East of about 2-3 Bcf a day to the 4-4.5 Bcf per day post-Rex East, whereas the supplies going West, or the Pacific Northwest on the Northwest Pipeline, are in Kern River to Nevada and California, is running between -- was running about 3-3.5 Bcf a day, and will be below 3 Bcf a day over the next year. Similarly, when we look at the Canadian gas, while it peaked over 3 Bcf a day in the past, we have it at just a little over 2 Bcf a day with some summer peaks going forward in 2009 to 2010. So that is illustrating some of the risks that California faces from changes in the North American gas market.

In other regions, the Mid-Continent gas will tend to flow to the Midwest because of the layout of the pipeline grid. The shale plays will move to the Southeast. The southern states, with their large local demand, will absorb the Gulf Coast supply. The Northbound flow from the southern states is about 12 Bcf a day and will not grow. And we have slow growth in LNG imports concentrated in the East Coast terminals. The Southwest gas, the San Juan, Sommel* [154:29], and the Permian and some LNG will be a major source of supply for California going forward.

Well, in that environment, competing for gas, let's look at little at the economic determinants and economic outlook. As we know, we are in the worst global recession in post-war era. If you are looking at risk, there are certainly many risks that are apparent now, but more could arise later. Globalization, the fact that we have very pro-cyclical policies, imply that risk will come from many different sources. The point I would make on the economic outlook, point 1, is that we are in a two-speed world; the brick nations, Brazil, Russia, India, and China, are a very important part, a growing part, of the world economy. The next time you are in one of the airport terminals and you look in the bookstore, in the international, the editor of Newsweek International, has just published a book saying that this century is going to belong to the Second World, the brick-type countries, and the enormous changes in the way the world will work in the future. And there is a lot of truth to that. But in a two-speed world economy, a lot of the growth -- most of the growth -- and in some respects, commodity growth, commodity demand, and commodity pricing, will be driven to a growing extent outside of the U.S. So the risk comes from the international.

Oil producers are another area where there has been substantial economic growth. And oil producers with their high dependence on the oil market, are also a source of geo-political risks. And then we have the Euro Block, which is a part of this OECD. The Euro Block is using -- is pursuing a path of recovery that involves much less fiscal and monetary stimulus and has been undertaken in the U.S. And there is certainly some experiments going on there that could create risk for us, especially in the area of LNG, depending on the shape of the economic recovery.

When we look at the U.S. alone, in terms of the economic forecasts and how it may affect demand, we are in the midst of five quarters of economic decline. We expect GDP to turn positive by the fourth quarter of this year, and to get smaller growth in 2010. The recession started in December of 2007, it was exacerbated during the banking and credit crises of September 2008. The financial crises are substantially different. Studies have shown, looking at the history, that the extent and depth of the recession is much worse when it involves the financial institutions, and primarily focused on the financial institutions. When we look at what it means for growth for different sectors of the U.S. economy, the first point I would make here is that we actually have a three-year hiatus of growth, the slow growth of 2008, the negative growth of '09, the slow growth in 2010, and we actually will have lost more than three years of normal growth over this period. Secondly, there are tremendous trade pressures developing in terms of the declines in exports and imports. This does not show the cyclical sectors, but clearly the recovery from the recession is going to be timed to the recovery in the housing and the auto sectors, which is at least a year and a half, or two years away. So we surprisingly still have a fairly reasonable demand for natural gas, even in the environment where the economy has stopped growing.

I want to turn now to talk a little bit about the oil market. In this two-speed world, two things are happening that is related, in part, to the slow growth in OECD nations. OECD nations have had negative demand in oil for 14 quarters and, up until the last two quarters, that centrally have been covered, we had world growth in oil demand because of the non-OECD countries. And that is something that we will resume again, given this two-speed world. So, again, that is putting the commodity pressures on the demand side outside of the U.S. But the real point of what is happening is the use of subsidies in some of these countries. Now, when you add up what consumers would pay at market prices with what they actually pay for their energy, you get a total of somewhere around $300 billion of effective subsidy of energy purchases worldwide. And when you are talking about a commodity like oil, that has notoriously low price elasticities. Did anybody in this room stop driving when the price of gasoline went to $4.50 a gallon, or $5.00 a gallon? Anybody? No. No price elasticity. Or very little in the U.S. When the price of oil went to $147 and people were paying their $.10 a gallon in Venezuela, or their $.15 a gallon in Asia, they did not stop driving. So the whole effect of price increases and bringing the market into balance, to bring supply and demand in balance, falls upon the American consumer, the Canadian consumer, and some of the European consumers. It means that we are much more vulnerable to the price shocks, and we are the ones that have to absorb the price shocks. And I would submit that this is a very important point that we are getting price shocks and volatility in our commodity prices because we are the ones in the world who absorb them. If you combine that with the fact that we are in the slow growing part of the world, and the people with the subsidies and the people who are non-absorbers, as it were, are in the fast growing part of the world, I would say that the shocks are going to get worse rather than be moderated.

My point on natural gas is that there is a somewhat rational explanation for a number of the price shocks that we have seen. Let's start off by putting together data on supply and demand, and inventories, is to look at the 12-month change. I picked the 12-month change for demand in inventories. Commonly, people do look at year-over-year change in inventories, but looking at demand on 12-month moving average. It helps to point a picture of what is going on in a cyclical sense, that makes it easier to see the pattern of what is happening, what happens when demand -- when you have a demand shock. If you are to do a study and look at the inventory change in any given time period -- a month, a week -- then you are to ask the question, is that inventory change due to demand, or is it due to supply. Running some regressions and doing some tests, I found that 70-80 percent of demand shocks get transmitted into inventory. And I think that is an important point. If we want to blame price volatility on the producer and prices are really explained by inventories, and if 80 percent of a demand shock gets put into inventories, then it is not the supplier who is shocking the market, creating the price volatility, it is the consumer. Consumers do not want to hear that. Consumers do not want to be told that when they drive a car, they pollute because they are emitting CO_2. We as individuals do not want to be told that, when we use electricity, that we are emitting SO_x or NO_x, or CO_2. We like to be told that it is the auto companies' fault, or it is the Utilities' fault. When we buy gas, when we drive the price up, we would like to be told that it is the supplier's fault, but it is just not true.

Going on, price follows inventories. This is a little less than inventory and demand, but there clearly is a relationship. When inventories are at an all-time high relative to normal, prices tend to be at an all-time low; if inventories hold 500 Bcf above Euroco* [164:00] levels, we are going to have low prices for a long time. I do not want to give you a lot of numbers, but I would point out a few numbers here. On the top of the chart, when a price forecast for 2009, most recent one, is $3.85, that is a huge reduction from the 2008 price. For the Rig count, I am looking for a Rig count that will average about 700 gas rigs for 2009. Now, on the first half of this year, the rig count started up well over 1,000. To average 700 through the year, we are going to have to get down to the 550-type range, which implies a continuing decline. Yesterday's number was 685, so we are going on a continuing slide on production probably through October or November, if not through the winter months. When we look at this lead-lag cycles, not only does demand fall -- demand and price have leads and lags -- as the price goes down, we see the Rig count fall in a much delayed pattern, and we have seen production level off, but it still is not clear that production has decreased, so there is a certainly a lot of lags on how supply is adjusting to this price decline. So our bottom line on natural gas is that demand began declining mid last year, and production is just starting to decline, so we have continued price pressures through 2010. The demand decline may continue to the end of 2009, even 2010. Prices are reacting to the weak economy, the weak demand, and to high inventories. The Rig count crash is too late to balance the market this year, this summer. And the drilling slump may lead to production declines in 2010 to 2010, just when demand is recovering.

One final thought, looking at a history of forecasts, in the spring of 2007, summer of 2007, we did a forecast at Global Insight, and our economic assumption about the Manufacturing Production Index is shown here in the upper blue line. Taking the Manufacturing Production Index that we have at the present time, it is significantly lower, and it is almost like a permanent shift down in output, that is closure of Ethylene plants, closing steel mills, closing other major energy consuming entities, the big decline in the auto sector. And it does have the effect of lowering natural gas demand. We do see natural gas demand in the industrial sector recovering to some extent, but it only recovers to about 90 percent of what it was in the 2002 base year, which was not a great year to begin with. What it does mean to me is that base load demand is not going to recover. And natural gas markets are going to have much more weather sensitive demand, as Dale mentioned. And with the combination of a growing utility use of natural gas to generate electricity, which is also highly weather sensitive, there certainly are huge risks in the natural gas market going forward. We looked at gas going to premium markets away from California, and you are looking at a two-speed world where the really -- the Brazils, the Russias, the Indias, the Chinas -- are running some of the commodity prices, the pressures on commodity prices. We have seen the subsidies, the $300 billion that can put the absorption of price risk on the OECD. We have seen a lot of leads and lags and how markets adjust in putting pressures on prices. And we have seen a big increase, potentially even bigger increase, in weather sensitivity for natural gas and electricity. And I think those are some of the risks that you are going to have to deal with. Thank you.

COMMISSIONER BOYD: Thank you. Any questions, comments from folks in the audience? Ruben. Thank you very much.

MR. TAVARES: Okay, Jim, thank you very much. I guess we are opened up for public comments. Anybody who might have any public comments, either here present, or out there, is welcome. Any comments now? I guess we do not have any comments from the public.

COMMISSIONER BOYD: You run a tight ship, Ruben. You are right on time.

MR. TAVARES: Yes, we are. So those are the presentations that we have this morning. This afternoon, we are going to have another two presentations and a panel discussion. So, it is up to you.

COMMISSIONER BOYD: Okay, it is time to break for lunch. We will break for one hour and be back according to that clock, which I do not think is exactly right, well anyway, in roughly an hour. Thank you.

[Off the record at 11:59 a.m.]

[Back on the record at 1:13 p.m.]

MR. TAVARES: Okay. Well, we are back. Our next speaker is actually going to make a presentation from afar. He is David Hoppock. He actually is from the Climate Change Policy Partnership at Duke University. David holds a Masters in Public Affairs degree from the University of Texas of Austin. He received his Bachelors of Science in Civil and Environmental Engineering from the University of California at Berkeley. So, Commissioner Boyd, you will like him. He is a Research Analyst now for the Climate Change Policy Partnership at Duke University. His work focuses on Energy Efficiency Policy and Natural Gas Markets under Federal Climate Policy. He is going to be presenting the results of one of the studies that Peter Puglia this morning described. So David? Are you there?

MR. HOPPOCK: Yeah, can you hear us?

MR. TAVARES: Absolutely. David, go ahead.

MR. HOPPOCK: Okay. Thank you for having us. I am also here with Eric Williams, who is the Co-Director of the Climate Change Policy Partnership. I wanted to start real quick with a little about who we are and what we do. So we work on low carbon economy infrastructure and policy issues, so some examples of our work include CTFs* [1:40], efficiency offsets, and transportation. We work with the Nicholas School and a couple of other groups at Duke University, and we have three corporate partners, Duke Energy, Conoco Phillips, and MeadWestvaco. I am not able to switch the slide, so could someone go to the next slide for me?

MS. KOROSEC: David, can you try using the up and down arrows to switch the slides?

MR. HOPPOCK: I am. And I did page down, as well.

MS. KOROSEC: You did page up, page down. Okay, can you try exiting out of full screen, and then going back into full screen?

MR. HOPPOCK: Okay. Before it gave me a little icon saying full screen.

MS. KOROSEC: Full screen, there you go, and try now.

MR. HOPPOCK: Okay, let me try again. Okay. It is working now. Thanks. All right, so the reason we did this modeling project for the other vehicle was to discuss concerns that natural gas prices would rise under climate change legislation because of increasing natural demand primarily from fuel switching, from coal to nature gas in the electricity sector as a way for the electricity sector to reduce their emissions. This increase in demand would, of course, cause natural gas prices to increase which is a big concern for a lot of industrial uses who are very dependent on natural gas prices, and have a harder time passing through prices than utilities do. So our goal was to present a range of forecasts given different technology development scenarios. And please stop me if you have any questions. It was kind of hard to hear people earlier, so please state your questions loud.

The climate policy we used is based on S2191, Leiberman-Warner. We chose this one because EIA developed this scenario specifically for NEMS* [4:06] and we begin our modeling with the 2008 version of NEMS*. We had our own version. And the point was to include a cap and trade mechanism in our modeling effort. We revised certain inputs for all [inaudible] [4:25] of our scenarios, and these are revisions to the 2008 version of NEMS, again, it has changed a bit in 2009. So we increased the unconventional natural gas reserves to reflect increasing unconventional natural gas reserves, so we were working on this last summer and that is when we started to get a lot of reports about the Haynesville shale, the Marcellus shale, and others. So we basically added the Haynesville shale to the unconventional resource base. We restricted LNG imports because of uncertainty about the U.S.'s ability to compete with countries in East Asia and Europe on cost; on LNG, we did not want there to be too much LNG supply available to the model. We also added the ability to retrofit existing coal plants with post-combustion capture technology, so the ability to add TPS doing generation technology. This is code from the National Energy Technology Laboratory. I am going to let Eric speak a little bit about this.

MR. WILLIAMS: Yeah, we think that carbon capture is the route to post-motion capture technology, it is an important technology, especially in modeling, you know, capturing scenarios. The ability to maintain, I think, whole capacity by using, you know, its retrofit is an important option to have available, too. We have another project on carbon capture and what, well, the modeling that we do on that other project, we need to have this option also.

MR. HOPPOCK: And finally, the medium power plant construction costs, the overnight construction costs, better reflect what we thought were better numbers representing actual prices that we found in the literature, and if people want it later on in the presentation, maybe in Q&A, I have a slide that shows this.

So the next slide shows our scenarios. We had a total of 10 scenarios, the business as usual scenario, which had the same technology assumptions as the referenced scenario, just without carbon gas. So I would like to start by looking at the cost going across the natural gas extraction scenarios. So we have a high natural gas extraction technology scenario, basically meaning we are getting better at getting natural gas out of the ground quicker than the referenced scenario, and then we have a low natural gas extraction technology scenario. So we are still improving natural gas extractions, just not at the rate of the referenced scenario. And looking at the left column, these are the electricity sector technology assumptions, so we have high electricity sector technology development, so fewer generation technologies developed quicker, meaning maybe some cheaper to build, and we have our referenced case, and then we have our low electricity sector technology development scenario where fewer technologies improve at a slower rate than the referenced scenario. We then included two additional scenarios, kind of as a "what if," if certain key technologies are not available for a time in the future. So in Scenario 9, it has the low electricity sector technology assumption and it restricts new integrated gasification combined cycle coal plant with carbon capture storage and new nuclear plants. So it does not allow the model to build them until after 2019, so the model's historic building of it is 2020, and Scenario 9B is the same, except without the retrofit options throughout the modeling period, so the retrofit add-on -- unfortunately you cannot really turn it on and off in a certain year, so you either have to include it, or not include it. Just a reminder that, you know, things have changed since we conducted our modeling. So, for example, the model assumes the real [inaudible] [9:16] at 2.4 percent. Obviously, that is not going to happen this year. We also likely underestimated unconventional natural gas resources, so the 2009 version, then, includes both the Haynesville shale and the Marcellus shale, our model does not include the Marcellus shale. In addition, there have been other reports saying basically what everybody has been saying today, that there is a lot of shale gas. There was a Navigant report that came out last summer, it says we have a lot of shale gas, 88 years worth is the current assumption level, and then Cambridge Energy Research Associates came out with a report a few months ago saying that natural gas supplies are no longer supply constrained in the short-term, being that the price will largely be determined by how much it costs to get it out of the ground, of course that does not cross targets* [10:16]. And then there are other questions about how much it costs to build a plant because the prices of commodities, things like steel and copper have definitely come down since 2008. So to begin with our natural gas sold, this figure shows delivered natural gas prices for electricity generators, so how much electricity generators pay, including the costs of carbon, so looking at the figures, the bottom line from about 2010 on, and this is the usual case without [inaudible] [10:58], so obviously with a cap, prices are higher, and our highest prices are our most restricted technology scenarios, so Scenario 9B has the highest prices, and our lowest natural gas prices are the most optimistic, the electricity sector development scenario. The one thing we noted was that the electricity sector development seemed to have a greater impact on future natural gas prices than natural gas sector technology development.

This table shows the percent change in natural gas demand from the referenced scenario and, for the reference scenario, it shows economy-wide natural gas demand for this peak per year, that is the gray row. So for our scenarios, there really is not much of a change in overall natural gas demand. And for only one of our scenarios, we have added a trade where you find natural gas technology development and low electricity sector technology development, is there any real increase in overall natural gas demand? Interestingly, for our restricted scenarios, so 8, 9, and 9B, where the harder to build plant carbon capture storage, you do not see a jump in overall natural gas demand. It is more or less the same as the reference scenario.

So to summarize, delivered natural gas prices steadily increase with the carbon cap, largely because of the price of carbon, and prices are highly dependent on electricity sector technology development. So we get good at things like IGCC, natural gas prices are lower, and natural gas demand is stable for our scenario.

So next, looking at the electricity sector goals, this is the average retail electricity price, so industrial, commercial, residential. Again, the bottom line is business as usual, with no carbon tax, and including a cap raises the price of electricity. So, again, our most restrictive technology scenarios may have the highest electricity price and the most optimistic electricity sector technology development scenarios have the lowest electricity price. And these more or less err on the allowance prices, so the models determine allowing prices endogenously. For six out of nine of our scenarios, the allowance prices are quite similar. They generally start at about $20 in 2012, about $80 in 2030, these are real 2006 dollars. For Scenario 9B where there is no ability to retrofit existing capacity, we have significantly higher allowance prices, and then, for our two high electricity sector technology development, we have placed the lower allowance prices which more or less mirror, again, average electricity price.

So looking at the change in average retail electricity prices in a table form and these are 2006 spent, real 2006 spent, per kilowatt hour. You have a pretty big increase in electricity prices, so electricity prices increase about 50 percent for the referenced scenario, and where we restrict technology development, we have even larger increases. So Scenarios 8, 9 and 9B, the low electricity sector technology development, were 20-25 percent higher, again, than that. So there are fairly large jumps in electricity prices, as to be expected with the current gap. This is total electricity generation, so the top line, again, is no carbon capture; so I would say the take home message from this figure is that consumers respond to higher electricity prices and demand either grows very little, or grows flat without a carbon tax. So, again, the highest electricity sector development scenarios for technology has proven quickly that it does increase a bit, so we are very conservative on what it should be in the sector technology zone, demand stays more or less constant for our modeling material in 2030.

Next, looking at coal electricity generation, the top line, again, is business as usual. We see a relative uniform decrease for all our scenarios, so [inaudible] [16:45], the carbon cap, the [inaudible] [16:48], electricity generation, but for none of the scenarios could we really see a precipitous drop and it stayed fairly consistent across the scenarios, regardless of how well technology and GTS developed. Contrasting this with natural gas, electricity generation. There is a bit more spread here. I would say there are general spreads or a bit of an increase. We have one scenario that is pretty significant increase relative to other scenarios, and that is where we have high natural gas sector technology development and low electricity sector technology, and the low scenario is high electricity sector technology development and low natural gas sector technology development.

Next, looking at renewables in electricity generation, so for six of our nine scenarios with a carbon cap, renewable generation increases significantly. It has more than doubled, so as compared to gauge without a carbon cap, and then for the low electricity sector technology development, we [inaudible] [18:09], but not as much. And interestingly, for areas where we have the science renewable generation [inaudible] [18:19] lower natural gas generation, and vice versa. So this is another way of looking at the data. So this is electricity generation by source for the entire country using 2020 units of terawatt hours for all 10 scenarios, so I will just explain the different colors. The bottom, the light blue kind of aqua is nuclear generation, the darker blue kind of purple is coal, the gray is natural gas, and the black is coal. The main thing to note about this slide is that a carbon cap starts discrete total electricity demand relative to -- without a carbon tax. So there is not a whole lot of differences between those in 2020. So looking ahead to 2030, we do see a spare amount, more variability. One thing that we thought was interesting was that coal generation for the low electricity sector technology scenarios, so scenarios 8, 9 and 9B, the three on the right, we actually had more coal generation for those scenarios than we do for our other scenarios. The other thing we noted is the kind of substitution between renewable and natural gas generation, depending on technology development. So where we have high electricity sector technology development, we have more renewables than natural gas, and where we have low electricity sector technology development, we had more natural gas on those renewables, indicating that renewables in natural gas are kind of substituting for one another. This draft also shows that. So this cumulative natural gas global generation, so nationwide, all the generation by natural gas. So summing it up from 2008 to 2030, a lot of blue -- the light blue is natural gas, purple is billable generation, so the first thing I would note is that the sum of the two columns is fairly constant across the nine scenarios with the cap, but for the different scenarios, sometimes we have more natural gas generation than renewables, and vice versa, again indicating that, for our scenarios, natural gas and renewables are substitutes for one another more so than for coal generation.

So next, looking at the capacity factors, these are average national capacity factors for coal and natural gas, so our business as usual scenario, the capacity factor increases relative to that. I am sorry, I should have said this earlier, the solid lines are coal capacity factors, and the dash lines are natural gas capacity factors. So we have a big sort of increase in coal capacity factors with the carbon cap, but for every scenario, coal capacity factors are at least double the natural gas capacity factors. So to summarize, coal generation increases, with that increase relatively constant across all of our scenarios. Taken separately, the two scenarios, we have large variability in renewable and natural gas generation, but when we throw them together, that total is fairly constant across our scenarios. For scenarios with high electricity sector development, coal generation, natural gas generation, and for the opposite, a natural gas generation, we see renewable generation. And when we restrict coal generation technology to carbon capture and storage, we do not -- we are getting at least three full generations together, but we do significantly increase prices. So those technologies are increasing prices and delivered fuel prices. So on to our discussion of our results. So for our modeling period for our scenarios, coal remains primary base load generation stored, natural gas not a substitute for coal generation under a carbon cap for our scenarios. The evidence for this are the capacity factors for coal that are approximately double that of natural gas, and for all of our scenarios through 2030, coal input prices are lower than natural gas, and I have a slide that I can show that demonstrates that. What are substitutes are renewables and natural gas and the ability to retrofit is critical to contain cost. In conclusion, all [inaudible] [23:59] are concerned about natural gas prices under carbon cap, the ability to implement TPS* is very important, so we would suggest pre-funding for research development of pilot scale and full scale demonstrations of TPS* technology and allow the pipelines and whatnot to actually be built, and we would also suggest the same kind of support for renewable generation, specifically improving the technology, because renewable generation can increase demand for natural gas for electricity generation. So with that, I would like to open it up to questions.

COMMISSIONER BOYD: Thank you. This is Commissioner Boyd. A question about carbon captures and the storage of 9GCC, I know your conclusion recommends funding research, this agency is pretty deep into funding research, working with NETL managing one of the seven regional carbon capture and storage demonstrations. Since a lot of people are highly dependent on carbon capture and storage, and yet I know personally that we are still deep in the research arena of this, I know it can be a little bit tricky to come up with any accurate cost representations of IGCC or carbon capture and storage. How do you deal with that?

MR. WILLIAMS: Uhm, we did our best in looking at the literature that is out there for, you know, all these bottoms are quite speculative, and one of the -- and it is certainly an uncertainty, as well as the amount of carbon capture and its roots that the NIMS Model chose to develop in price signals, you know, there is a question as to whether the pipeline storage infrastructure would be in place to be able to actually ship and store that CO_2, so it is definitely, you know, there are a lot of uncertainties around the cap and, in theory, going back and re-running a few of the scenarios with the latest version of the stimulus package, and with Waxman-Markey, rather than Leiberman-Warner cap, and, you know, in the process we may also do scenario review with the different assumptions about the cost of IECP and the cost of retrofit to see what -- try to do activities around this.

COMMISSIONER BOYD: Okay, thank you. I think -- we appreciate what you have done and hearing about it today, and I think we would really be interested in the results of any additional work that you outlined that you may carry on. Another quick question is just about your assumed cost of nuclear. I do not know how much of this morning you were able to listen to, and how much you have looked at that, but that is one of the things that we studied quite a bit in the last several years as to whether there is any future role for nuclear in California, and among the issues that arise for us are the seemingly really expensive aspects of developing a nuclear facility, and I think that was emphasized by one of the speakers this morning. Do you think that when you did this work that the cost data used for nuclear was pretty well in line with what the thinking is with regard to cost?

MR. WILLIAMS: Well, I did not -- I am sorry, I was not able to sit in on the study earlier, but we are assuming about $4,900 a kilowatt for the cost and to run these scenarios. And that was based on Cambridge Energy Research Associates, they have a power plant construction cost index and we were able to derive nuclear cost index from that, and then apply it to some earlier EIA cost assumptions, and so arrived at a considerably higher cost assumption than EIA and, you know, based on literature, we felt that it was a reasonable cost assumption, and that our [inaudible] [29:52] to evaluate any agreement.

MR. HOPPOCK: That was one of the main differences between EIA's analysis of Lieberman-Warner and ours. In their model runs, they built new nuclear capacity and, for our construction costs, the model chose to not-build any nuclear [inaudible] [30:23] 2030, for our runs. So I think that cost number makes a big difference on the results you end up with.

COMMISSIONER BOYD: Okay, thank you. Ruben, any questions from folks in the audience or on the Web?

MR. TAVARES: Any more questions, comments to this presentation? Okay, I guess we do not have any. David and Eric, thank you very much for your presentation. Okay.

MR. HOPPOCK: Thank you.

MR. TAVARES: Okay, next we have Dr. Kenneth Medlock. He is a Baker Fellow of Energy and Resource Economics at the Baker Institute and also an Adjunct Professor of Economics at Rice University. He leads Energy Forum's National Gas Program and teaches courses in Introductory and Advanced Energy Economics. Dr. Medlock has most recently worked on the impact of climate change policy on the global energy market, the impact of shale in the North American and global gas markets, the efficiency of national oil companies, the causes or consequences of changes in oil prices, and the future of Russian and Caspian natural gas and the role of Bolivia and the South American energy balance. His research is published in academic journals, book chapters, and industry periodicals. With Ron Soligo, he won the International Association of Energy Economics 2001 Award for best paper in the year of the Energy Journal. Dr. Medlock also served as the lead modeler and the modelings of [inaudible] [32:43] for the National Petroleum Council, a study of the long-term natural gas markets in North America. He also contributed to the 2006 National Petroleum Council Global Oil and Gas Study and the title is *Facing the Hard Truths.* Dr. Medlock.

DR. MEDLOCK: Let me begin by saying thank you for inviting me to talk. I think the day has been fairly interesting and it sure gives you a lot to think about. What I am going to try to do through the course of this presentation, and this was really at the request of Ruben, I am not only going to present the reference case of the Rice World Gas Trade Model, but I am going to talk about sort of how we derive some of the inputs into the model, so you can understand some of the uncertainties that we deal with a little bit better. And I think that is a good launch point for, a) the panel discussion that will follow this, but, b) really just coming to grips with, you know, why do ex post we typically look back at forecasts and think, "My God, how could we have been so wrong?" So I think it is a very important thing to really understand. And it really raises a broader question, why do we even bother? And I will share in a minute thoughts on that, but forecasting is a very valuable exercise if for no other reason than going to the exercise itself, because it helps you to understand a lot of the things that actually influence market outcomes. And, at the end of the day, that is really what we are most interested in, is variable influences, rather than a point estimate.

So whenever we talk about the Rice World Gas Trade Model, it is always fun to show this picture because it kind of puts things into perspective. This picture is a composite of satellite photographs on clear nights from around the world. You can see the continents, you can see all the little white dots, those are the places where the lights are on. Those are what we think of as demand syncs. Those are the major load centers in the world. It is where we need power, it is where we ultimately need natural gas. You can see the entire eastern half of the United States, you can see California pretty well lit, you can see all of Western Europe, you can see all of Japan. There is one little thing I want to point you to, for those of you who know your geography, you can pick out South Korea very quickly, it is the big bright spot just above the southern tip of Japan. Well, if you look at that map, it looks like South Korea is an island, doesn't it? North Korea is dark. It really points to a very important reason why we actually do what we do. We are primarily engaged in understanding the cost of geo-politics, what sort of costs do those import on markets. And so what we is we try to understand those costs and, in effect, quantify those costs through various scenarios that we run with the model. The other thing that is on the map are the big bright blobs of color. The brighter the color, so as we go all the way to red, real bright red, the more intensely endowed the region is with natural gas resource. Now, this picture really only has conventional gas resources on it, so the shales and whatnot that we have heard a lot about are not portrayed here, but, even with the very large shale assessments that we have heard talked up to roughly 84900 tcf, give or take, it still pales in comparison when you look at the big bright red spot in the middle of Russia. So what we have to think about when we think about modeling a global gas market is how do we connect the big bright red spots where all the lights are on. That is really, at the end of the day, what we are interested in doing. And as you can sort of come to understand very quickly by looking at the map, that process is going to be riveted with all sorts of interesting geo-political type stories, as well as substantial costs, just physical costs of developing infrastructure. And just to reiterate something, actually, that Darryl mentioned during his presentation, there is a lot of resource near the water. That is the other thing that should jump out off this map at you. Big bright red spots in the Middle East. Look at West Africa. Look at North Africa. A lot of those prices are already positioned in the export LNG, but given the resource endowments in a lot of these regions, they could easily expand.

So we have developed, using the Market Builder software from Altos Management Partners, we have an academic license to its use to do precisely the kinds of studies that have been talked about. We have developed the Rice World Gas Trade Model. I am sure a lot of you, if you have heard Dale talk, have heard him give his pitch about the model. He presented some stuff using the Altos World Gas Trade Model and, like I said, they have got it tied to their power model, which is a pretty powerful tool. But the model is interesting because, just to be blunt, I think it is the only software on the market that actually treats the development of the depletible resource in a textbook fashion. It does not assume supply curves, it actually uses the cost of capital. And it forces you to develop resource into reserves so they can be extracted in a profitable manner. Now, having said that, it does sort of open the door for another layer of complexity. How do you cost resources when you have perhaps never even drilled a well in a particular region? I mean, that is a very difficult thing to grapple with. One of the things that we have actually done is we started with the National Petroleum Council data that came out of the 2003 study, where F&D costs and cost curves were developed for resource basins in North America. We mapped those costs into geologic characteristics for the basins within North America. It created an econometric relationship, in effect, and applied that to the basins around the world. And the data for the basins around the world with regard to technical recoverable resource, and field size, and depth distributions, all that good stuff, is available from USGS, so it enabled us to construct a cost curve for those prices where we have very little information. But the model is interesting, it is non-stochastic, so it does not allow you to sort of put probability distributions around any of the cases that you run, in fact, that would be inherently very difficult because every bit of data that you load in has its own density function associated with it. So, in other words, how do I know in which sort of probability distribution about a variable I am in? I have no idea. We typically center on the means and we run scenarios, it is a sort of common practice, if you will.

So how do we actually think about projections when there is a lot of uncertainty? Well, I already said this, but when we think about forecasting, it is no the point estimate that is of the most interest, at least it should not be; if that is the reason you are forecasting, then a) you are always willing to be wrong, and b) you are going to make a lot of bad decisions. Really what you want to understand is the sensitivity around that particular point estimate. If there is a wide range of sensitivities, so there is a potentially huge range of outcomes, it tells you that any decision you make around that sort of mean point estimate is inherently filled with lots of risk. If there is not a lot of range around that sort of point estimate, that tells you, well, I can sort of take this mean at face value and contingency plan around it. And that is a very important thing to really understand and to think about when you are making policy or you are planning long-term capital investments. Corporate planners go through this process once a year, at least. And they grapple with all the uncertainties and understanding all the uncertainties. Policy makers do the same thing. So everybody is sort of tackling this issue in a similar fashion. I guess the magic is in the interpretation, if you will. So really understanding those sources of uncertainty is really what the most important aspect of any sort of real modeling exercise is. Once you understand those uncertainties, you can, like I said, contingency plan. You can sort of construct the worst case scenarios and see what sort of costs those actually bear. You can construct very optimistic scenarios and see what sort of costs they bear. I will say this. The one problem with constructing a lot of different scenarios is -- especially when you are in sort of the arena of policy -- a policy maker might become attached to a particular scenario that maybe promotes something that he or she is in favor of. It happens in corporate circles, as well, quite frankly. I have seen it really influence decision makers when a particular project team really likes an outcome because it favors their particular project. So it can be sort of interesting to try to grapple with those things. But at the end of the day, it is more important to understand what drives you away from the mean, so to speak.

The other thing that I want to point out when we start thinking about projections is there is a difference between the long run and the short run. And a lot of times, that difference is not really well understood. Long run forecasts are really heavily influenced by technology assumptions, assumptions regarding resource assessments and long-term costs of recovery, projections regarding economic growth, so 20 years ago, if somebody had been able to look into their crystal ball and sort of envision what has been going on in China, that would have been great. A lot of people did not. It almost seemed to hit the market like a bang in the late '90s that China was suddenly eight years into it, this massive importer of oil and gas resources. So, economic growth is a really important thing to really understand, as well. Also structural frameworks are important when you are doing long-term modeling because they give you a way to deal with these uncertainties. In the short-run, you are really, in terms of uncertainty, driven by demand side factors. You know, weather uncertainties -- you know, is it going to be really cold this winter, or is it going to be mild? Is there going to be a really active hurricane season? These sorts of things, you really have no way of really predicting, but you can certainly do sensitivities around a particular case under varying sets of assumptions with regard to these kinds of things.

I was actually reminded of something when I was putting this presentation together. Back in the '70s, I guess it was, there was a lot of effort by the U.S. Government to really develop long-term macro-economic models. And these models have a lot of value when you sort of think about the long-term; they perform very very poorly when you think about the short-term. And so they came under a lot of criticism, most notably in the economics literature by Econometricians such as Chris Sims. Basically what was shown is that if you move away from the structural frameworks when you are looking at short-term modeling, you typically do better with pure time series analysis, so econometric approaches. But if you sort of venture into the long-term, you need those structural models to understand how structural aspects of the market, if they change, drive the mean, so to speak. So it is kind of important when you are thinking about policy, when you are thinking about planning, to understand the difference between the short term and the long term, and employee the appropriate tool.

Within the Rice World Gas Trade Model, just real quick, I am going to kind of run through these slides very quickly because they are available out on the table if anybody is interested. And there is a lot of stuff available on our website, as well as in a book that was published three years ago, now, in a study we did joint with a group at Stanford. But there is over 140 regions represented globally, so all the big bright red spots you saw, some of them are sub-divided, and then some areas that are not on that map because they represent unconventional resources. And they are divided into various traunches, so you have associated and unassociated gas reserves, and this is kind of a pet peeve of mine, but people often misuse the word "reserve". We actually look at total gas resource when we model. A lot of that is speculative. And there is generally a distribution built around that parameter estimate. But it is not a reserve until it is actually demonstrated, or what we call "proved." But we also -- so what we do is we break things up into the proved category, what is known as growth to known, so that is just growth in existing fields, we use estimates from the USGS, actually, to obtain those numbers, which are also published on their website, and undiscovered resource, which is categorized typically as what some people call "yet to find." So it is resource that we think geologically should exist, we do not necessarily know if it does. Cost of supply estimates, as I mentioned earlier, are econometrically derived. We looked a the North American data and then extrapolated that data out onto the rest of the world. Now, we have gone back through the process of trial and error, and where we noticed things were happening that we know would never happen, or simply are not happening, we have been able to revise our cost estimates for some particular basins. And we have been able to augment, quite frankly, as time has passed, and we started this project in 2004, with data that has become available, or as has been published because of what is happening in the last five years in the gas markets globally. So it really is a process, it is never done. I am sure you guys know this.

We also account for long run sort of depletion costs, the idea that there is this rush to drill phenomenon, so within a given year, if gas prices are high and there is this sort of rush to go out and prove up as much resource, and develop as much resource as you possibly can, costs will escalate, and we have actually seen this, and I have got a slide here I am just going to show you that, you know, as price rises, costs tend to follow. And well, here, I will just jump to it, but we actually tried to account for that in the modeling framework, as well. This is actually another huge source of uncertainty when you really start thinking about modeling gas markets, is what is that sort of F&D cost? What is the appropriate F&D cost for any basin? And what is the appropriate benchmark? So if you think about the National Petroleum Council Study, which is where we started, that was released in '03, looking at long-term natural gas markets, the dataset that was used to develop F&D costs curves for the basins in North America basically span from '96 to roughly '99, okay? Well, if you look at this graph, you see that '96 to '99, look at that red line and look at that blue line, those are the EIA -- you know what the EIA is -- it is a well cost index they publish; the Bureau of Economic Analysis, the BEA, the CLEMS database, that is Capital, Labor, Energy and Materials. It is a database they publish and it is industry specific, it is broken down by an NAICS code. So you can actually extract oil and gas activities in the mining sector, and you see those are very similar. The BEA Index is a little bit more all-encompassing than the EIN Index focuses on well costs, specifically. But you see back between '96 and '99, those costs are relatively low, especially when you look at where they are today. So if we apply those costs face value, we are going to come out with a long-term gas price forecast that is probably around $3.00. So the question to ask yourself, well, is that appropriate? It is probably not appropriate. Because if I convert these to real, everything on this graph is just nominal. You will actually see that that course, that period in time corresponds with a trough. It is not that surprising. The price of oil dipped to $8.83, I think, in October of '98, so that is not that long ago, is it? Hmmm. But costs were very low, price was very low, and what we have seen since 2000 is really -- well, up until the middle of last summer, an exorable climb both in cost and price. So if you start to think about forecasting, do I use 2008 costs? Anybody want to hazard a guess? I would suggest probably not because you are going to overstate the costs of development and then you are going to end up with really high gas prices. Do I use 1998 costs? Probably not. Right? So what you have to actually come to grips with is, what is your view of, say, maybe the oil market going forward, if you are just going to focus on the gas market? And think about the relationship between F&D cost and commodity prices, in general, so you can think about what your view of commodity prices are, in general, if you would like, and then start to build scenarios in that way. What that will allow you to do is actually change your F&D costs consistent with a general view of a commodity basket. And then that will give you different outcomes, of course. When you start thinking about natural gas prices and projects that might get developed and sort of the regional implications, what are the flows of trade, all these sorts of things.

But this is something that is -- I know it is understood. I have actually seen other people talk about cost indexes that are similar to this. And it is very important to really capture this when you are forecasting because, if you do not, you are really missing a very important driver of what your long-term forecasts will be, right? What is your basis for cost? Very important. Yeah, 2007 costs roughly two and a half times what they were in 1998 for the exact same project, and nothing else is different. Geologically, it is identical. But it is two and a half times more expensive. That well exceeds the rate of inflation, just in case you are wondering.

Within North America, we have a lot of detail, largely because, well, Freedom of Information Act is beautiful, allows you access to a lot of information that you do not necessarily have in other parts of the world. But with regard to supplies, we have 56 regions. I have sort of aggregated up a little bit here just to show you what is in the model, just in the United States. In Canada, there are six, and in Mexico there are two. And I was just looking at this, I think actually the U.S. has expanded a little bit because of the -- and I know Canada is up by two because of the introduction of the new shales, which I will talk about briefly here in a few minutes. But anyway, there is a lot of detail on the supply side. There is actually more detail on the demand side. Now, why? Well, when you start thinking about modeling long-term markets and you are interested in regional trade patterns and the development of basis differentials, you really have to have a decent representation of pipeline networks. And when you do that, it means you have to site sync appropriately, so you need to break demand up so that it is located along systems in the right way, or you are going to get an aberration, right, relative to what really happens with regard to flows on pipelines. So we have taken a lot of care to do that. It turns out that you have to do this also when you think about LNG, in general. I will give you an example. In some of the initial iterations of the model, we had a lot less detail in Europe than we do today. And it really favored

Russian gas via pipeline over LNG quite substantially. However, once we got more detail, we were able to actually identify intra-regional bottlenecks, which really helped favor some of the LNG developments that you have seen occur over the past five years in Europe. To those of you not familiar with the European -- by 2011, just given projects that are either opening this year, or under construction, European LNG import capacity will be roughly 40 percent of European demand. So it is a big number for LNG imports. And that is up from -- I think it was 15 percent just five years ago. Things have happened very very rapidly there for lots of reasons we do not have to discuss, but energy security is a primary driver. But these regional constraints are really important to understand. So incorporating those actually promotes development opportunities for alternatives, and so that is where LNG really gets a boost, especially in Europe, at least as we have noticed it.

Demand is modeled in the U.S. in a much more disaggregated way than it is for the rest of the world simply because we have better data. We model it for power generation, industrial, residential, and commercial use. Industrial use, we have actually -- in the past, we have done this, but we ended up rolling it up because we found it did not make that much of a difference, but we used to break it out a little bit more finely. The rest of the world data is not nearly as easy to come by. And in a lot of cases it is suspect, especially in the less developed countries. We find that aggregated data looks better than when they try to break it down by sector, largely because definitions change over time, and data collection agencies change over time. The IEA does a real good job of trying to grapple with this, but it is a difficult thing. But we basically model rest of world demand in two broadly defined sectors -- power gen and then direct use. And so when we do this, we have to really lean on economic literature, you know, what is the effect of economic development on energy demand? And I am going to go through this, a couple of these things, in a minute. What is the effect of relative price movements on the share of fuels? So basically the idea is, if the gas price is increasing relative to the other prices, what should happen to the gas share? You might think it should fall and, in general, that is true, but the process we use actually allows for a variable of elasticity. So if gas share is very very low, the elasticity relative to the price elasticity is going to be very high, and that reflects -- there is no capital, there is no gas using capital installed, right? So it is going to be very difficult to sort of get that ball rolling. But if gas share is very high, that price elasticity is going to be very very low because you are basically wed to using gas at that point. We also allow for introduction of new technologies in varying ways. We focus primarily on coal gasification and alternative technologies. They are allowed to phase in. We do not just assume they are available at a particular point in time and drop them in, you actually have to have significant investments made to bring these new technologies online.

Economic growth. I mention this as a really important driver for understanding sort of long-term forecasting. And let me explain this picture real quickly. All the little blue dots are points specific to the United States, going back to 1790. Okay? So you see a per capita income along the X axis, so the horizontal axis, and you see a per capita GDP growth rate on the vertical axis. And one of the things you notice, which should jump out at you anyway, is that scatter seems to tighten tremendously around $12-15,000, okay? So this is the historical experience of the United States. If you plotted the U.K. experience, it looks really similar, and the reason I only use these two countries is these are the only two countries that I can get data going back to 1790 for. So what we did is we used this to construct a reference growth path. The reference growth path is the sort of brownish red line that goes through there. Before you hit $6,000 a head, the average growth

rate is about 1.2 percent a year. So there is this idea of a population growth trap. It is hard to sort of get going, basically. Once you get going, you really get going. You can see there is actually a paucity of data points between $6,000 and $12,000; that is because growth rates tend to accelerate through that range, and you sort of leap through that very quickly. And this is all in real terms and $2,000 terms, so you would have to inflation adjust if you want to put in 2009 terms. Then, once you sort of get past that $12,000 range, the growth rate tends to settle down around 2.1 percent or so -- this is in per capita terms, mind you
-- and they are fairly stable. So why do this? Well, there is this whole stream of literature that focuses on what we call "convergence." The idea here is that countries will converge, and originally it was to a common GDP per capita, so a common level of development, and then it sort of evolved because the data did not really bear that out, to something more like a conditional convergence idea because they converged to a common growth rate, which, at the end of the day when you look at the literature on economic growth models, is roughly the growth rate of innovation. So what we decided to do was look at the experience of developed countries like the U.S. and the U.K., figure out what this referenced growth path would be, and then fit data for -- I

think it was 70 different countries -- around this referenced growth path, their historical experience which usually only runs from 1971 to roughly 2006, to see how their growth rates actually converged to this line. We actually found that growth rates do tend to converge at this line, so take China, for example, in PPP terms, they are around -- they are on the low side of $5,000 a head, growth rates are very high. What we will actually have in the model is a continuance of that growth rate, although it will slightly decline until it gets in that $6-12 window, and then it will sort of go up a little bit more, and then, once you get to $15,000 or so, Chinese growth starts to look a lot like U.S. growth. It is very hard -- and this is per capita -- take $15,000 and multiply it by 1.3 billion people and try to add 10 percent to that. Structurally, that is going to be very very difficult to do. So looking at things in this fashion really helps us to put a structural framework around the idea of economic development. And, again, this is really critical when you think about long-term forecasting and you think about patterns of trade, and you think about what could emerge with regards to competition for resources.

General trends that are apparent in the literature that -- and I cite a paper that I was involved in, but there are multiple studies looking at this issue -- what is the relationship between Energy use and GDP -- you actually find across the literature evidence for declining energy intensity beyond a certain point. The idea there is that, as individuals gain a certain level of wealth, they start to demand financial services, things that are a little bit less energy intensive, and so those become engines of growth in most countries and, to the extent they are less energy intensive, is their share of the total economy grows, energy intensity follows. Now, this does not mean energy demand falls, that is a really important thing to understand, it just means that it grows a little bit more slowly relative to income. So what you have is an income elasticity that declines as the level of development rises. Now, the one thing that that highlights, actually, and this is an important point, is that for a more developed country where the income elasticity tends to be lower, the price effects are going to dominate outcomes, because if you just take a given price elasticity and you have 3 percent growth, let's say, in income in a developed country, that is going to give you, oh, roughly if income elasticity is .15, .45 percent growth in energy use. A less developed country, same amount of growth, say 3 percent growth rate, income elasticity say .75, you are going to have 2.25 percent growth in energy demand. So energy demand is going to grow faster even though GDP growth is identical in the two cases. Now, given that, if price were to go up by a particular amount in both places and price elasticity, let's just say hypothetically, is constant, the price is going to have a bigger impact on the outcome in the developed country than it will in the less developed country. I think this is a point that was made, I think, two presentations ago. It was alluded to, anyway.

Now, it is not so simple because the share of gas and primary energy really does influence how responsive you can be, because it is an indicator of how capital -- of the types of capital that are deployed throughout the economy. So if you are 70 percent gas, you have got a lot of gas using capital installed and it is going to be very difficult to move away from gas if gas prices spike, right? So your price elasticity is going to be very low. If you are at 10 percent gas, it is actually easier to rotate away from gas in the generation stack, so you have got a lot of other options. And so that is actually captured here, too.

Just a snapshot of over 300 regions. I already said basically '02 bullets. Pipelines, nothing is assumed. The only thing we assume is that there is an option to build something between two points. There are capital costs associated with developing any piece of infrastructure in the model. And we have to lay that on top of, of course, what exists, right? So there has been a lot of care taken in understanding what capacities these are of existing pipelines around the world, not just in North America, and modeling those appropriately. Coming up with capital costs is always challenging, the same issues that I talked about with regard to F&D costs face the steel industry, as well, therefore they affect pipeline development costs, too. And so what we have done is, while we have actually looked at a sample of 100 projects over a window of time between 2002 and 2005, we think that is roughly representative of where long-term costs ought to settle. This is a value judgment, quite frankly, but it puts you roughly at the mean between the '98 low and the 2007-2008 high, if you will. And we came up with an algorithm to assign capital costs for pipeline projects that do not exist, but possibly could. Variable costs in the U.S., we used FERC filed rates elsewhere in the world if we do not have published data on a particular project, and some data does exist, although it is very scant. We actually use rate of return recovery to calculate a terraphrate* [65:35] appropriate for that piece of infrastructure.

So, again, there is a lot that goes into just building a model, right? And without a doubt, anyone in this room could say, "Well, I don't agree with that assumption." Well, that is great. In fact, we revisit our assumptions all the time. As more data comes available, it really demands that we look at what is loaded into any given model, and reassess and reevaluate, and we do that. However, you have to start somewhere and that is actually part of the beauty of the determinist model like this, is you can run various scenarios, you can change inputs, and you can understand, well, maybe you do not agree with my assessment about the capital costs to build, you know, pipeline infrastructure, all right, let's change that to what you think it is. What sort of impact does that have? If it has very little impact, well, then we could probably agree that, all right, we disagree on this input, but it probably does not make that big a difference in the grand scheme of things. And those are the kinds of things that are important to really understand, you know, what are the sensitivities of these particular assumptions?

On the LNG side, and this has been a really fun one to follow, we actually use a hub and spoke network, we have played around with sort of modeling things on a contractual basis, you know, point to point specific with some diversion flexibility. And a lot of what we do at the Baker Institute, because we have this broad energy forum, and it is composed of members from industry -- all walks of industry, not just oil and gas, it is also renewables and banking industry, consulting industry -- and they actually give us feedback regarding our assumptions to try to ground what we do. And when we first started this process, a lot of people wanted to go the contract route because, back in 2004, 2005, that was sort of the consensus thinking, that is what LNG was, that is what it is going to be. So we starting building that in and then we started thinking, well, what if there is diversion flexibility? Then you really started to move to a different world where, you know, spot trading is more of a reality and what do you do then? So we started to go to the hub and spoke route. In 2006, we had another meeting, our Annual Energy Forum meeting, vetted this with industry, and they all agreed the hub and spoke approach was best. So it went from contracts to hub and spoke, and now we are getting a lot of feedback that we ought to have contracts in the model, so it has almost gone full circle. It makes you wonder what is going to happen in another two years. So maybe the answer is a combination of the two. We will certainly take it under advisement, but from the preliminary work we did, where we had contracts with a little bit of diversion flexibility, say 15 percent of volume, that was sufficient, actually, to drive price arbitrage across regions, and it does not really make a difference how you do it. So, as the market thickens, there will be more liquidity, there will be more opportunity to trade, and that is really one of the key principal points of a lot of what we have done.

There are other things that you have to assume. You have to assume what is a reasonable required return on investments. And this is just a blanket perimeter, this is something you have to apply to all investments, so if you are talking about pipelines where you get regulated rates of return, you are probably going to have a different required rate of return to move forward with a pipe than you will with an upstream development. So we have to take all that under advisement and account for that. You also, since this is a global model, you have to account for risk premium in doing business across different countries. And that is something we have taken a great deal of effort to do, I will not really go into all the details here, but there is a lot of information. As I have pointed out in this last bullet in the book, *The Geopolitics of Natural Gas*, which is a Cambridge University book, press book, and it was the result of a joint study that we did with Stanford's Center for Sustainable Development. Our reference case, which is what I am about to go through here with regard to modeling results is not necessarily our view of the world. You have to remember why we do this, right? We are academics. So you can take the model if you have a different interest, and you can change the assumptions and do different things and come up with your own view of the world, but basically what we do is we let commercial considerations drive all the outcomes in our reference case. And then we layer over the top of that geopolitical constraints, or other sorts of constraints that might arise, and that enables us to, on a one-off basis, quantify the effect of that constraint. A good example, there is lots of gas resource in East Siberia and stretching over to the coast, the Sakhalin Islands, for examples. It is not that far from the Korean Peninsula, it is also not that far from Japan, it is not that far from China, and, quite frankly, all the load in China is on the coast. So why don't pipelines get developed? Well, that is a good question. If you run this model, commercial considerations only, it builds very extensive pipeline that works in East Asia. It is sort of like saying, what if everybody else in the world goes along the same way that U.S. and Canada do? That is another way to think about it, right? And then you can go and you can say, all right, well, we know that geopolitically this is probably rife with all sorts of problems, so let's just restrict it from every happening, or we can raise the required rate of return for a project, maybe there is some rent seeking by one of the parties, or something like that. What happens? Well, it turns out it has global implications because if you have a lot of pipelines in Asia, you need less LNG, right? And so it changes the way gas actually flows globally. But definitely, when you introduce that constraint, the price effects are largest at the point at which the constraint is introduced, so South Korean prices, when you introduce that constraint, almost double, for example. So this is basically what we use the model for, this sort of an exercise.

So I am going to go through the reference case anyway, just because it is fun to talk about. This is a real quick example of a lot of the stuff that we have done; again, a lot of this has an academic focus, a lot of it has been published either in working paper form, currently on the Web, or it is actually in press. I will not read them all. Oh, I will say one thing, the last two studies we did, we looked at options for Russian gas, which had gotten a lot of attention, as you might imagine, by a lot of people in Europe, in particular, but also the study we did looking at potential oil for Turkey to develop an international gas hub, one of the things that really came out of that work was the importance of Iraq to the energy security long-term of Europe, which is not something that many people had really thought about before. So we actually presented this paper at a conference in Istanbul last summer and there were lots of representatives from Botas, which is the Turkish National Pipeline Company. They were way ahead of us, as you might imagine. Reps from Botas have been actively negotiating with the Kurds, in particular, for access to some of the gas fields that are in Northern Iraq to export to Europe, at the end of the day. This is something that has been going on for years, this is not brand new. It just turns out that Western companies shy away from Iraq right now, with good reason, there is not any really well established rule of law with regard to mineral resources yet, and so on and so forth; but it sort of opens your eyes that, at the end of the day, if things really do sort of get moving in the right direction there, the role that Iraq could have actually in serving European needs and, for that matter, as you see in the first sub-bullet under Options for Russian Gas, really offsetting the need for Russian gas in Europe. It is actually quite an interesting finding. We have also been looking at the effect of carbon constraints. I will comment on that at the end of my follow-up, because there has been a lot of discussion about it already. One of the really interesting things in the study we did is, if you have carbon constraints, we do actually find that it drives up the gas demand, specifically in the power generation sector. There is a little bit of an offset in industry because industrial demand dips because you have higher prices and basically you have migration of industry offshore, gas using industry offshore where carbon constraints are not binding. But it encourages shale development, which is happening right now anyway, but it also encourages more LNG. The

U.S., as large as it is, if it gets into the LNG market in any sort of similar way that it has gotten into the oil market, it really changes the nature of things geopolitically. It turns out the biggest winner, and this is a very controversial thing to say, but the biggest winner as a result of a really binding cap and trade type or carbon-type policy, is Iran because they are sitting on a massive amount of resource and nowhere to put it.

So some of the reference case results, you can see this is an aggregation of all the demands. You see substantial -- or, yeah, this is supply, sorry -- demands are next -- you see substantial growth from some of the Middle Eastern countries here, so basically all the grays to whites are the Middle East, you can see a lot of this. Most of that growth is driven by LNG development. And this goes out to 2040 in this particular slide. Russia remains very very important for the global gas market balance, although its share in the global gas market declines, and that is just a natural phenomenon resulting from growth in the Middle East and other parts of the world. Australia becomes increasingly important, especially for Asia, it is not just Northwest shelf and northern territory development, so Browse basin and Carnarvon basin is all offshore, LNG developments. It is also all coal bed methane that they found recently in Southeast Australia. It turns out, actually, down the road, the question was asked, does California get in the LNG business. We actually find, down the road, that it does, but just so you know, that development does not occur until you get well into the 2030s in our reference case runs. The U.S., I mean, it scales, sort of hides a lot of what is going on here, there is substantial growth in the U.S. supply picture, as well as other North America -- especially through about 2030, but then things really begin to flatten out because you run into resource constraints, especially in your conventional resources where things are in pretty steady decline from now forward. And shale can only keep up for so long. So at some point, the U.S. really does have to turn outward to meet its gas needs. The strongest demand growth is in the Middle East and, quite frankly, that is driven by the fact that it takes a lot of resource to make a lot of resource, and I do not know if you guys are aware of this, but the mining business is one of the most energy intensive businesses in the world, so that is a reflection of a lot of what you see there, as well as just general economic development in those countries as their resources are exported a little bit more widely. The strongest growth, though, is in developing Asia, as you might suspect.

With regard to global gas trade, right now, a large majority of gas is traded across international borders, is traded via pipeline. That will, however, according to reference case, change by 2029, LNG will become the dominant form of international trade. I know I told you earlier not to focus on point estimates, and then I tell you 2029, so write that down in your books, right? But again, right, this number does move depending on the kind of scenario we run. But the general point is, LNG becomes increasingly important in the global gas balance, that is the takeaway from this. LNG exports -- you can see Australia, as I mentioned before, very very strong growth, good resource base, small population. Enough said. That is why it ends up doing what it does. That is very important for the Asian market. You can see here the Middle East, which collectively is the largest single region of LNG exports, down the road. Other -- Africa actually grows quite strongly, but then begins to basically level off. You can see out here in the very long run growth from Russia, and a lot of that is Barents Sea development, the Arctic Russia developments. LNG imports, same thing. I mentioned a minute ago, the U.S. eventually has to turn outward and you look at this sort of dark blue ledge here in the middle -- I am going to blow up the U.S. here in just a minute, but you can see here this dark blue ledge really starts to grow in the late 2020s. Other regions, you can see the Chinese get really big into LNG, and various things in other Asian countries, as well. So a lot of the trade in LNG still does occur in the Pacific Basin, that does not actually change. More trade occurs in the Atlantic than it has in the past, but the Pacific, because of the way consumers are located around the world, it really has to rely on LNG. What is the price outlook? I have actually shown two here, this is Henry Hub from 2005 forward, and NBP which is National Balancing Point in the U.K. We see longer term, basically what happens in the model is a transportation differential arises between the two. What happens in the modeling framework is, if anything were to drive you away from that equilibrium, trade would occur to immediately correct it. Now, this is an annual model, so there could be seasonal aberrations, if you will, that arise around this. But you can see long-term prices at the hub are, you know, between $650 and $720 or $730, roughly, in the reference case.

So a little bit of a focus here. This is basically what happens with U.S. demand through 2030. You can see most of the growth is driven by the power gen sector. The reference case does not have any carbon constraints layered over the top of it, but that is an important thing to remember because, right now, to us, it is still a scenario, there is not any legislation that has actually been passed, so sort of think of that as a scenario on top of the reference case. Now, once the legislation is introduced, that will change. But I have a note there, you see that the power sector average annual growth is about 1.3 percent a year, going out to 2030, you layer in that carbon constraint and that thing jumps to just over 3 percent a year. When you have compound growth on top of the roughly 6 tcf demand, that number gets really big, okay, by 2030. So with that in mind, the result is not that different from what Dale actually showed you earlier in his presentation. It is a little bit lower than what he showed, but it is not that different.

On the supply side, a lot of what drives the outcome in North America is shale, a massive resource that we have always known was there, we just did not really have the technical know-how to develop it in a cost-effective manner. I will tell you a little story because this is a fun one when you talk about the endogeneity of supply to tell, when we did the natural petroleum count study, you know, 3, the resource assessment for the Fort Worth Basin, which is where the Barnett shale sits, was 6 tcf. Okay? Back in the early 2000s, gas prices were creeping up, some developers thought, oh, it is a marginal play, but it is one that I could get into and it is starting to look like it will be profitable, so let's do it. They got in there, they realized, wow, there is more here than I thought. And they figured out ways to actually go in and fracture rock, and increase recoverability from a particular well, and lo and behold, you have the Barnett, which is now the largest single producing play in North America, it is over 4 tcf a year. That is a big number from a single region just west of the Fort Worth. So technology has played a huge role in really driving -- and price, for that matter. If prices had stayed in the $2 to $2.50 range like they were in the '90s, we would not be talking about shale right now. This is a very important thing to remember. And that is why the approach is as important as the data you use, right? Because if you can go after what is generally deemed to be technologically feasible, and there are costs associated with those technological developments, you are going to typically get a better long-term answer than you will if you just load it in supply curves.

Now, these estimates -- you see this range between 125 and 840 tcf's, so this is across multiple studies. And the low end is dated, admittedly, and the EIA has updated it in their 2009 outlook, their shale estimates, so it is higher than that now. But that range is fraught with uncertainty, too, just to be perfectly blunt. And there typically, when we talk about these big ranges, we are talking about technically recoverable resources. Those are not reserves, right? A lot of this will simply, at a $7.00

price, not be recoverable because you are not going to make any money on it, you will not even break even. Technology can change that, to some extent, by lowering cost of development, but talk about uncertainty. There is a lot going on in the front of fracturing. A colleague of mine at Rice University, Andy Barron, he is doing a lot of work in the field of Nanotechnology and Rice does a lot of down hole reservoir stuff using nanotech. Propants, which are in the fracking fluid, basically hold the spaces open in the rock, more or less, they have developed a ceramic-like nanotech propant that is lighter than ceramic, and therefore -- and harder -- and therefore, when you force all that water down under all that pressure, you actually get -- I think it is between 50 and 60 percent increase in the fracturing area when you actually inject, and so that raises recoverability from a particular development. They have actually -- this has gone beyond the laboratory phase, they have actually recently bought a manufacturing facility and they have got venture capital to start producing the stuff, so this could have a really big impact down the road on shale in terms of lowering its cost. So thinks like that are always going on, and that is the one thing that you always have to kind of keep your ear to the ground on, what is coming next. Right? We like to talk about technology and developments, well, there is a lot of down hole technology that has been developed over the years that keeps fossil fuels in our cars and natural gas running through our pipes. So it is important to keep an eye to that, as well.

COMMISSIONER BOYD: Does that fracking fluid ultimately solidify? Or does it remain a solution always?

DR. MEDLOCK: Well, the water is actually pumped back out and that is one of the issues in a lot of cases, yeah, with the gas, right. So it is what you do, you know, disposal is one of the big issues in terms of water contamination because, right now, companies do not have to divulge what they are using in their fluids, so if they are using a chemical that might be environmentally detrimental, that could be bad, well, they do not actually have to tell you. My stance and my colleagues' stance at Rice on this has always been the industry needs to get out in front of this before it becomes a bear that cannot wrestle, and actually show that what they are doing does not cause any environmental damage.

COMMISSIONER BOYD: Yeah, I am reading an article about the cattlemen and the water supplies.

DR. MEDLOCK: Exactly. So you know, that is going to be interesting to watch. I am going to point that out in a few minutes, actually, so good leading question. Other shale plays in North America, up in Canada, there has been a lot of interest in the Horn River, in particular, which is the northern-most in sort of Northeast B.C. That is the one that is tied to the potential at the Kitimat facility. Just as a data point, no matter what scenario we have run, the Kitimat facility never develops as an export facility. And I talked to a guy, actually, who used to be involved in that, and evidently that has been proposed as an export facility before, I think back in the '70s, was it? And then it switched to an import, and now it is back to an export, so it is this great piece of land and they just do not know what to do with it, I think. Anyway….

This is a picture of the assessments. You can see total shale gas from North America, this includes Canada, it is 472 cf, this is our mean assessment in our model. These have recently increased largely because of new data that has become available for Haynesville and Marcellus. Haynesville and Marcellus were a little bit lower, but the increase added to an incremental 115 tcf's, so that is a big number now. It has not all cost the same. That is a very important point. These resources typically have what you refer to in a lot of cases as core and non-core areas. The core areas are sort of like the sweet spots and these are the lowest cost areas, the shale is the thickest, most thermogenically* mature, there is a lot of nice sort of things about the shales in those areas that may not be true if you sort of move to the edges of the play. So you cannot just lay a single cost estimate over the top of the whole thing, you are going to over-produce, in effect. And, again, technology, as I mentioned a minute ago, is a huge ex factor in shale because this is a brand new thing. Now, when I say "brand new," you are going to have to take it with a grain of salt. They have been producing gas from the shale formation, which is the Marcellus, for over 100 years, they just have been using old vertical well technologies, low-flow rates, but the flow rates were very steady, they just always came, right? Well, now we are going down there with this horizontal drilling technology and fracturing the shale, we are increasing the amount we get from a well, and that is going to lower the cost because recoverability factors go up. So that is just the first step, I think, in the technology revolution that is shale. So we will see where it goes.

This is a picture of the U.S. production out to 2030. The big red bit at the top is shale. You can see Alaska there at the bottom coming on, and it actually really becomes a commercial venture around 2020, 2021, 2022, so the early 2020s. So as that moves forward, and there has been a lot of stuff in the press lately about the Alaska pipeline with Exxon signing on with TransCanada, and that is going to be a fun one to watch, but one of the lessons I have learned, and I am still relatively young, but the Alaska gas pipeline project has always been the project that is always 10 years away, right? So in the 1992 MPC study, the powers that be said, oh, we will have Alaska gas in 2001, 2002. Well, that came and went, right? The '99 study, all right, 2010. Came and went. 2003 study, 2014. Well, 2014 is going to come and go. Right now, a lot of the people that are actually involved in the development are talking about 2018, 2019. I am pessimistic just because I think history has told a pessimistic story, but we will see.

Now, one of the things I want to point out here, that I think is actually an important thing when you talk about how modeling can help policy makers grapple with very complex issues, is what is the role of the OCS, the role of shale, and the role of Alaska in balancing the North American gas market? We have actually done a study where we opened the OCS for natural gas development, and one of the things it did, on top of all of this, is push that Alaskan ledge out by a decade. Okay? So it is sort of like a net benefit trade, right? You steer away from developing Alaska, which appeases some environmentalists who are against Alaskan development, and the trade is you develop the stuff that is closer to home, which is in the outer Continental Shelf region. Now, again, there is a lot of uncertainty about how much resource is out there, so it could be shorter time period, or it could be much longer, hell, we just do not know. A lot of the stated assessments for OCS are based on data that is over 30 years old, so we have got to actually do an assessment to really know.

COMMISSIONER BOYD: I am surprised to think there is a trade-off between the environmental concern about pulling that gas back out of the ground in Alaska because of OCS.

DR. MEDLOCK: That is a different issue, but you are right.

COMMISSIONER BOYD: It is the economics of the pipeline, more, isn't it?

DR. MEDLOCK: Well, I would agree with that. As a matter of fact, as a position I took when Governor Palin actually withdrew the rights that, I guess it was Murkowski granted on the pipeline project, well, when gas is $14 in MCF, that looks a lot easier to do, so I think price was in her favor. A lot of the developers up there have long argued for a subsidy simply because they know that if gas prices are in the $4 to $5 range, it is going to be difficult to make money off that, because it is a very expensive project. But those are in the economics in what you see here, so as price rises, that begins to become at the margin competitive, and so Alaska does actually develop in the early 2020s of the model -- unless you do some things with the OCS.

Shale supply, this is just sort of a snapshot in the reference case of what is happening with all the shale basins that are loaded into the model. You see the Barnetts, the big orange one in the middle? It basically, according to the reference case model output, it is going to basically hold serve from now on, you are not going to see a lot more growth out of the Barnett, but it is not really going to decline, either. Where you are going to see a lot of strong growth is in the Marcellus, and the Haynesville, and the Fayetteville, and unfortunately for California, those are not real well situated to directly serve California's needs; however, it does reduce the need to export Rockies gas east. So the market is a continental market, and by displacement, these shales do actually serve the California market. I am going to show you the implications for that because they are actually quite different, for basis, quite different than what Dale actually showed a bit earlier.

COMMISSIONER BOYD: I am waiting for the British Columbia shale gas and California.

DR. MEDLOCK: Yeah, that actually comes on -- here is -- the Horn River is that purple one right at the top. Now, one of the things that happens with Canadian shale is it basically comes on to support tar sands development and maintain export levels into the lower 48. It does not have a lot of market to move into because it is a) basis disadvantaged, and b) it is a long way away from the major load center. So really all you are doing is offsetting declines in the conventional resource base in Canada. So, you know, absent some -- I hate to say it, but absent some subsidy or some real strong government push to move this gas south, it will come on, but it is going to come on more slowly than its lower 48 counterparts because it is farther from market.

So what about LNG? All this shale coming on, a lot of discussion about, you know, the U.S. becoming the market of last resort. Do we go back through the experience of the '70s where there was this rush to build these LNG facilities, and they ended up mothballing two of them? No. This is actually a picture of what happens with U.S. LNG imports. You can see 2008 is pretty bad, it was pretty bad last year. In 2009, there is a bit of a recovery up through 2011, but from 2011 to the early 2020s, you actually see really really low utilization rates on all this new capacity that has been built. Does that mean we mothball facilities? No. Because I can tell you, the way a lot of these facility owners and capacity holders are thinking about these things now; you can see it to some extent in the way they are actually filing for certification of re-export gas. It is a real option to them. An LNG re-gas facility represents roughly 10 percent of the value chain in an LNG development, so it is a small percentage of the cost, and it gives you an outlet when you do not have one, otherwise. So these are sunk costs, they are there, they are going to continue to be used, just at really low load factors. A lot of them will turn into storage, quite frankly. That will be the primary service they serve. Now, you get out past 2020, you really start to see this thing creep up. And, again, that speaks to declines in conventional resource basins in North America, not necessarily shale, right? Shale becomes an increasing proportion of total production. It just cannot offset the natural decline that we are seeing, especially the Gulf of Mexico, with regard to gas production.

So a quick comment because, you know, I like to talk about annual vs. seasonal. This is data straight from the Department of Energy. You see 2006, which is the grey, 2007, 2008 by month. You can see this sort of pattern that seemed to emerge in '06 and '07 of an increase in imports of LNG to the U.S. in the summertime. Now, the reason that happens, typically, is there is no where to put gas, even if it is contracted in Europe because you run out of storage real fast. That makes the U.S. market vital, the U.S. storage market vital for balancing the Atlantic basin. Okay? So this gas comes here, ultimately pushes gas into storage. Does that mean you would draw from storage and serve Europe? No, it is a displacement argument, right? You fill up storage more rapidly and I expect that to be more the norm, so it sort of calls into question using sort of five-year averages, if you will, for storage levels anymore because the convenience yield on storage is different now. There is a structural change that has happened. And so I think that is something a lot of people are going to have to re-think, and I think they will over the coming years as you see this really emerge more and more. 2008 is an aberration. And I say that because, if you look at what happened in Asia, a record number of cargos, especially in the summer months last year, were pulled out of the Atlantic Basin, into the Pacific Basin, you see a lot of nukes off in Japan and what do they use when they do not have nukes? They use gas. They were paying upwards of $20 in mcf for a cargo of LNG on a spot basis in Japan. So those nukes are being reactivated. As they are reactivated, that displaces that gas that was needed, puts it back in the water in the Atlantic Basin, and it has got to go somewhere. If there is no load in Europe, it is going to end up in the U.S., and it is going to end up in storage, and you are going to see patterns that look more like 2007 than 2008 going forward.

So some of the basis differentials. And this is a point I was alluding to a minute ago. The bottom one may be the easiest one to follow. This is just two ways of portraying the same picture, basically, what you are looking at here. But you can see the green on the bottom is the basis at O pal, and we actually see it strengthening relative to where it was the past couple of years because you have got some pipeline capacity that opens. But it pretty much holds steady, right? And that number right there tells you a lot about what happens to California basis on the model. That gas does not get pulled east as heavily as it would if shale was not in play. Okay? That means it is pushing West. And that means, if you look at this orange line, that is the SoCal border basis, if you look at the -- where is PG&E -- the red line, that is the PG&E basis, all right? Now, I cut this off at 2030 because it is just easier on the eye. Where this picture gets consistent with what Dale showed you earlier is after 2030, okay? Because conventional resources decline so heavily, those are primarily in the Eastern part of the United -- east of the Rockies, right, that you do begin to pull a little bit harder on Rockies gas towards the east, and that really does put a lot of pressure on basis locations in the West. And that is where, as I alluded to earlier, you start to see a desire for LNG to come to the West Coast, and that is where the model actually begins to develop it, is after 2030, when that basis really starts to decline. Again, the reason that basis number never stays the way it is, it is not necessarily because the Rockies are going bananas, it has more to do with -- it is a displacement argument. You have got relatively moderate demand growth in the reference case, and you have got a lot of shale. It means the Rockies gas does not need to move east very hard, and so it does not.

Uncertainty. How much time do I have, Ruben? Ten minutes? Okay. So a lot of this stuff, I have hinted at already. But it is fun to talk about because it is the basis for scenario analysis, quite frankly. And I hate to say it, but when you think about investment behavior, one of the biggest uncertainties that faces the market is policy. What is going to happen? Right? Arguably, you know, the specter of carbon policy has loomed over the coal sector for a while now, right? What are we going to do? I think that ship has kind of sailed now, but it is just -- and there is a huge literature on this, the idea of investment under uncertainty -- if you have uncertainty, it puts an option value to waiting and so you wait. Right? Try to gain more information about what is coming. And this is not unique to energy markets, either, it is actually true of any market you will look at.

Climate policy is really important. One of the things that is sort of in the latest round of the

President's new budget is the idea of changing the expensing rules for upstream developments, what are known as IDC, or Intangible Drilling Costs, typically you are going to expense those in the year they are incurred. They are talking about removing those. I will tell you something interesting -- because I think it is interesting just to let you know things always come full circle -- I found a paper when I was looking at this, that was written in 1982 about the very same thing. So it tells you that, even though it may not go through this go-around, you can almost guarantee it is going to come back up again at some point. Right now, I think the climate is very positive for it actually happening because the government is in need of revenue very very badly because of all the money that has been flowing out. So they are looking for ways to raise tax revenue and this is effectively one of those ways. Now, will it just crush the independence? That is a question of debate. I think it is going to hurt them at the margin, for sure, because they do not necessarily have the scale to deal with an increased tax burden. How much the majors come in and sort of pick up the slack is a question of debate, it really has to do with the scale of the projects the independents are involved in, and the majors are not interested in doing small projects, they just do not do it. Right? They are interested in capturing economies of scale and they go for the big elephants. There is also an issue of tax incidents, so if you actually change an expensing rule, how much of the burden actually falls on the producer, and how much ultimately gets passed on to the consumer? It is probably somewhere between -- well, it is definitely somewhere between zero and 100 percent, but it is probably more likely somewhere between 25 and 50 from some of the preliminary stuff I have seen with regard to how much actually gets passed on to consumers. So the majority of the burden will actually fall on the producer.

Other uncertainties which I have talked about, upstream costs, uncertainty in assessments, fuel price relationships are incredibly important to understand. I recently published a paper with some colleagues at the *Energy Journal* looking at this issue, in particular. We actually identified technologies, a really crucial determinative relationship between crude oil products and natural gas. So the introduction of combined cycle technology, for example, in the '90s helped really shift the way that relationship looks -- long-term relationship looks. Economic growth and development -- there are all kinds of sector-specific issues we could sort of talk about on the demand side, and NIMBY issues also matter. That is where policy sort of gets in the way. I have alluded to the project where we looked at developments in South Korea and

Northeast Asia. You can sort of view that as a kind of NIMBY issue by proxy, if you will. It prevents the development of a piece of infrastructure that has an implication for cost. The thing, though, you consider and lay all these uncertainties out -- and I am sure I have not exhausted the list, right -- the thing that is really important is, if you have a framework, a structural framework, you can put all of these pieces into, you have a way to deal with those uncertainties, and that is the value in forecasting, that is the value in generating outlooks because you can understand any influences of changes and particular variables on an outcome.

I am kind of out of time. I do not know if I can go through some things -- this is all in the packet, so…. One thing that I just want to point out, there are a lot of studies that have been done, we have seen a couple discussed here, looking at the effect of carbon constraints on energy markets. Talk about uncertainty? This is a collection of all the price paths out to 2050 from all those modeling efforts for carbon, so you guess where the price is going to be. This is what people look at. They say, "My God, any of these could happen." It depends on what you assume about technology, what you assume about the use of offsets, what you assume about how binding constraint might be, whether or not you can bank credits, all sorts of things come into play, all right? Huge amount of uncertainty about what is going to happen.

COMMISSIONER BOYD: The thing I keep hearing is, first, there is what might be the price of carbon, and then there is the discussion of what price of carbon does it take to influence the change that allegedly is desired by legislation, regulation --

DR. MEDLOCK: Exactly, and we have been involved in looking at a study looking at how carbon prices will affect gas markets, and in doing so, we have to broaden our scope a little bit, the thing about the energy market, more generally. And Bill is exactly right, carbon prices need to be endogenous and so we are modeling them as such. We actually find, given the capital cost assumptions we have got embedded in the model which are, at this point, DOE assumptions, we have got some input from industry that indicate prices are going to be -- costs are going to be higher than this, but to encourage the kind of innovation and investment, really, in these sort of new innovative carbon-free type technology, so things with ccs and so on and so forth, you need carbon prices to be between $100 and $140 a ton. And if it is any lower than that, you are not going to get the investment necessary and you are going to end up just really, well, having a penchant on the margins. So you kind of have to bite the bullet. I mean, if you are sitting on Capitol Hill and you see your constituency suffering because carbon constraints are becoming really binding, you might be tempted to argue for, you know, a new allotment of allowances. Well, that is not going to get you there because then they keep carbon prices too low and you are not going to see the kind of innovation that you need to see, and to really affect the kind of change that you need to affect. So it is going to be a contentious one, I think, to watch. The affect on natural gas demand, when you look across these scenarios, is huge. This is just the core scenarios, so it is very small subset of what I just showed you. There is a 15 tcf difference by 2030 across the scenarios regarding natural gas. And as was pointed out in the previous presentation, most of that difference is driven by your technology assumptions. This is why scenario analysis is valuable, right? If you can identify the technology that will be most effective in instituting a change, if you are going to have policy that is directed at really trying to get there, then you can identify that technology, you can design the appropriate sort of set of subsidies, or incentives, or whatever you want to do to try to effect that change; if not, you are just sort of throwing darts in the dark. Right? You do not know where you are going to be. All right, and I will just end with that. I will just open it to questions, I guess?

COMMISSIONER BOYD: Thank you. Fascinating. I have blurted out my questions during your presentation.

DR. MEDLOCK: That is okay, it makes it more fun. I like the give and take.

MS. KOROSEC: We have a question online.

MR. DEAVER: He is not on the phone, so maybe I can just read it to you?

DR. MEDLOCK: Sure, that is fine.

COMMISSIONER BOYD: This is a question that came in online, correct?

MR. DEAVER: Yes. The question is, what happens to the price forecasts if the Alaska pipeline is not built?

DR. MEDLOCK: Ah. Well, the natural gas price in North America does rise, but it is not this catastrophic event because, if you constrain the system -- and that is effectively what you are doing -- you push on a lot of different margins, and so you do see a price increase, but in a long-term setting, it is on the order of $.15 to $.25. It is not a big number. And, again, that is because you push on other margins. There are other basins you can produce from, there is LNG you can draw from, and this is a really important point about modeling gas markets on a global setting -- the core analysis that was used in the NPC study, the NEMS model, they basically make assumptions regarding LNG imports. Right? When you do that, you inherently run into a constraint with regard to how the system can respond, and you will get much bigger price impacts when you have domestic constraints levied on top of that, and that can be a little misleading, quite frankly.

COMMISSIONER BOYD: C'mon forward.

MR. BRATHWAITE: I am Leon Brathwaite. I work here at the Commission. Ken, your presentation really touched on my issue here and, anyway, you know, we government types, we hear the word "speculation" and we all are expecting bad things, okay. I would like, if you can, to just if you can elaborate a little bit on the role of speculation in markets and especially, in particular, in the market that we are asking about, which is natural gas markets. I would appreciate if you would give some insights on that.

DR. MEDLOCK: Absolutely. I will begin my answer by saying that is a different presentation. The answer to that question is sufficiently complex that I am actually working on a much longer piece related to that issue. And it really centers on understanding what happened to energy commodity prices over the last eight years. Speculation, in my opinion, undoubtedly played a role in what we saw happen. And speculation can take the form -- take a number of different forms, but you have to preface everything you say, after you say that, with markets have to be tight in the first place. If they are not, then if speculation begins to drive price up, you will encourage a reduction in demand, and an increase in supply, storage will build, and then the whole thing -- the bubble pops very quickly. If markets are tight, though, so in effect you have a very vertical demand curve, and if supply constraints -- so you have a vertical supply curve -- you have got an infinite number of price realizations at which the market can clear, in effect. And so, as you sort of get into that situation where price starts to get bid up, because maybe there is speculation that, you know, peak oil is here, or Chinese demand is going to grow out of control, or we are not going to be able to keep up with it on the supply side, or you name it, there are lots of things that were sort of bandied about, private corporations are not investing enough, you know, all these things. Then when you start to see price creek up and you do not see that storage build, then that adds fuel to the fire. And that is something that we actually saw from 2005 through roughly 2008. Now, the drop in price coincided -- there were a number of reasons why it dropped -- the banks got in trouble and they started to unwind a lot of the positions. As a matter of fact, I have a nice graphic that I got from the CFDC, data from the CFDC that shows the amount of open interests in WTI contract. It typically was a lagging indicator of price up until about 2006. And so, if you are looking at that date in 2007, which is when a lot of people first started looking at it, you know, open interest is a lagging indicator, how can it be driving anything? Well, from 2006 to 2008, it was a major leading indicator of price, so something structurally was different about that period. Now, how much it drove price, I cannot answer that question. And the work I am doing is not complete yet. But it definitely played a role, and I actually believe that some of the rules with regard to trading, and trading institutions that were changed in the early 2000s played a major role in what we saw in the last six years. And hopefully that is something that will be addressed by members of Congress in the very short term, or else we are going to see some pretty radical spikes because, one of the things that happened the last part of 2008, the world economy slipped into a recession and you saw flight back to the dollar, the dollar strengthened, right? That means people were unwinding positions in commodities, and they were going to the dollar first as a safe haven, right? Well, things started to calm down and what are we seeing this year? The dollar has been steadily weakening. Where are people going as a hedge against inflation? Oh, right back into commodities again. You have got to ask yourself, what is really driving? You see price go in April from roughly $45 a barrel, today it is about $70. Demand is lower than it was last year, why -- I mean, the market has to balance, right? So do not get me wrong there, but there is a huge amount of spare capacity globally right now. Saudi Arabia is sitting on roughly 4 million barrels of spare capacity. So if they wanted to, they could inflict massive change in the global market overnight. Usually when you have that much spare capacity sitting on the market, that is a buffer, but for some reason that is not doing anything right now. So I would not be surprised if, by the end of the summer, we did not hit the mid-80's again. It would not surprise me in the least. But the bubble will pop. I have got some colleagues who actually called it "sucker rally." Take it for what you will. But, again, that is a lot of presentation. I have a lot of stuff on this, but….

MR. BRATHWAITE: One follow-up question, please. I understand your point about the movement in prices that we are seeing right now, that we have seen in the last few years, but do you think, without speculation, we can have properly functioning markets?

DR. MEDLOCK: Absolutely. We did up until 2002.

MR. BRATHWAITE: Okay.

DR. MEDLOCK: One of the accounting rules of change was -- and this is largely -- I will say it -- it was largely an Enron phenomenon. If you were speculating in over-the-counter markets, you could not go into the NYMEX and hedge against those speculative plays ad infinitum; now you can. And it is still called a "hedge," therefore there is not a position limit put on you. In 2000, you could not do that. That is one of the biggest differences. So that is one of the accounting rules I am talking about.

COMMISSIONER BOYD: You could have gone all day without saying the word "Enron."

DR. MEDLOCK: I know. I paused.

COMMISSIONER BOYD: But, so be it.

DR. MEDLOCK: But Ken Ley and his friends sort of led the charge on that bit of regulations, so -- changing it, anyway.

COMMISSIONER BOYD: Any other questions? Yes.

MR. MAGALETTI: My name is Mike Magaletti and I also work for the Energy Commission. Since we are on the topic of speculation, could you give us a short description of the United States Gas Fund which is an Exchange traded fund, and the United States Oil Fund, and what you know about their positions? These are beasts that are just showing up on the radar in the last six months.

DR. MEDLOCK: I am trying to remember, yeah, I do not know much about those, to tell you the truth. Somebody in the audience might be able to elaborate. I think the Oil Fund, didn't that have -- it had an enormous position, didn't it. I think I remember reading something about that.

MR. MAGALETTI: I have not been following the Oil Fund, but the Gas Fund seems to be acquiring a substantial position in the two prompt months. Somebody was telling me 25 percent; at one time there was a rumor of 75 percent.

DR. MEDLOCK: That 25 percent is equivalent to the share I heard about in the oil market. But I do not know. I honestly do not know, so I cannot answer that question. Sorry.

DR. NESBITT: Dale Nesbitt. On that, I know just enough to be dangerous, so I will give you a dangerous answer. The Gas Fund, if you look at the forward curve right now, it is about as contango as it has ever been. And if it is me, these funds are very quiet, as I understand it, they do not say much, they do not do much, but if you are $3.00 today and $7.00 next year, you might go long on gas and make a lot of money doing that. The oil curve was extremely contained going until 60 days ago, and then the front end of the curve came up, and so you will see investment strategy changes in those two funds. That is the dangerous part -- if I am wrong, I am wrong. But I think that is what has happened. That is what I understand.

COMMISSIONER BOYD: Okay, thank you very much.

DR. MEDLOCK: Sure.

MR. TAVARES: Well, thank you, Ken. Are there any more questions? Well, welcome, Commissioner Byron. We had a good discussion today, but we are going to continue the discussion. Before we proceed, I just wanted to make a point here that the written comments to any of the papers that we published, or the comments that you heard today, are due here at the Commission on July 8th, so if you want to provide some comments, please send it to us. Commissioners, we are scheduled for a short break here, if you do not mind, and then after that we will have a panel discussion.

COMMISSIONER BOYD: Make it a little shorter than your agenda shows up, though. Let's call it a ten-minute break. It will be longer, they always are, so that is why I am trying to call it a ten-minute break, as you assemble your panel.

MR. TAVARES: Okay, sounds good. Thank you.

[Off the record at 3:02 p.m.]

[Back on the record at 3:21 p.m.]

MR. TAVARES: Our last event here is the panel discussion. Ross Miller, staff from the Commission, will be moderating this panel. We are going to be talking about, you know, different questions that we posed in our notice of the workshop. And the panel participants are Dr. Dale Nesbitt, Dr. Ken Medlock, and James Osten. So Ross, go ahead.

MR. MILLER: Good afternoon. Just as initiating discussion, you will notice on the agenda, when this was posted, this was listed as "Handling Uncertainty in a Natural Gas Market." I think we have had ample demonstration in the presentations today that there is an acknowledgement of uncertainty, and there is some pretty sophisticated handling of it. With the papers and presentations, we have seen many examples. And I think they have maybe gone beyond the questions that were posed in the workshop notice, which by comparison may seem a trifle naïve. The first one was: Do natural gas market participants acknowledge uncertainty in the gas price forecasts? They certainly do. I think it would have probably been an equally important question to ask whether the users of these forecasts do because the consequences to them of not understanding the uncertainty, especially if they are using a single point, date specific forecast, that they select, or that is provided for them, can subject them to some fairly significant vulnerabilities. So the other question we had in the workshop notice was, given the tremendous uncertainty associated with trying to quantify the major key drivers or input variables that lead to resulting price forecasts, is it even feasible or useful to attempt to produce single-point forecasts? And that is the only question in the bulletin, but I do not want to confine the debate to that because the answer, as we already have heard, is likely to be, no, or a very conditional yes if, or yet, but…. The follow-up of that question was, anticipating perhaps that it is not quite feasible, how should uncertainties be incorporated into the natural gas market assessment?

I am going to take a little aside right now just to paraphrase in very broad terms what I thought we heard today. We have heard a lot about the very very complex relationships between key drivers and outputs in natural gas market assessments, whether it is the demand, the supply, or the price; certainly about things as specific as locational predictions of where those things are going to occur, and certainly date-specific point estimates of any of those things. Everyone has been pretty clear about the need to have a good understanding of these relationships to really gain useful insights from any of these assessments. I think they have all admitted that there is a great amount of uncertainty about these key drivers, and that necessarily makes the outcomes uncertain that we would like to see in terms of price, or demand, or supply. And on top of everything else, given those assessments, there actually -- unless you are physically constrained by historical capital investments, as some of the presenters have talked about, there really are quite a few options available to people to deal with these uncertainties, different actions they can take to protect themselves against the risks these uncertainties pose, or vulnerabilities. And that is what makes decision-making so difficult, you have got a very complex set of interactions, you have got a lot of uncertainty, not all of it, if any of it, very well characterized, but you have many different things you can do. So that is where, to me, and I think I heard some of the presenters say outright, that is really where the benefit of modeling comes in, is to help you understand all of that and not necessarily make a single prediction of where the future is going to be. And I think a follow-up for decision-makers, or policy-makers, is if you accept the notion that it is not really feasible to make accurate point forecasts, but we have to make decisions, and we know we have to make policies, so the real question is, how do we fashion policies that do not rely on such forecasts since we know they are not likely to be accurate? So with that as background, I would first ask if any of the panelists would like to add something to that, or elaborate from what they said earlier today, given those questions, or what they heard some of the other panelists say this afternoon? Dale?

DR. NESBITT: I do not have any elaboration on it.

MR. OSTEN: Yes, I have two slides that deal with the role of future price volatility because it is an underlying issue, and I do not necessarily have to handle that now, but I would like about two or three minutes to do it at some point. Yeah, if you just go to the first slide, let me give you a very short background. There was an article written in the *Financial Times* on July 27, 2008, and it says, "The usual suspects are financial investors driving up the cost of commodities." And there are two questions here, the first one is, "Do the futures markets themselves, because they allow speculation, result in more price volatility?" And the second question is always what to do about it. And the two examples that I thought were very interesting, both the role of futures market vs. non-futures market, was what happened in 2008 with the price of commodities without a futures market, which went up a lot, vs. the price of commodities with a futures market. Now, in this slide on the top are seven commodities, including rice, iron, ore, and steel, various alloys, non-Exchange traded commodities with very high increases, whereas the ones we thought we know, gas, oil, and others, had somewhat smaller changes in price. So you could make the case that having a futures market and regulating the futures market does not necessarily increase price volatility, it could decrease price volatility. The second example has to do with the onion futures market. In 1958, the Congress of the U.S. debated furiously price speculation in onions futures, and they passed an act that prohibited the trading of onion futures. The act was passed in August of 1958. In November of '59, the ban came into effect. And I will let you judge for yourself which period had the most price volatility, the one where they had a futures market, or the one without. I think it is clear that the period without futures market had the highest volatility. The second example comes from Berlin wheat futures prices, they were very upset with the price volatility and they banned the wheat futures in January of 1897. A year later, they had a huge price [inaudible] [9:37]. After the re-introduced the futures in January of 1900, prices seemed a bit more stable. So there are three examples comparing the futures market and no futures market. So you can make the case that it is really more market, the supply and demand, that is creating the price volatility, not the speculators or existence of the futures market. In some ways, the futures market moderate the volatility, then the question is what to do about it, and I think you have to address the supply and demand. One thing that you are doing here in California, which I admire greatly, is the focus on the smart meters, and then being able to give the right signals to the market, and being able to control the demand side. I think that in and of itself is much more effective than it would be regulating the futures market.

DR. MEDLOCK: Can I -- I just want to make a couple statements, actually. Having a futures market or the absence of a futures market are sort of two ends of the spectrum. I do not think that anybody said here really suggests there should be no futures market because, undoubtedly, there is a huge financial urge from this. The role of futures is very valid, it brings a lot of liquidity, it brings the ability to deal with risk, and we have lots of very positive things associated with the existence of a futures market. Really, what we are talking about when we talk about the role of speculation is the role of regulation within a futures market. So how does the futures market function, not whether or not it exists. So those are sort of different issues. So to say that you look at a commodity price with and without a futures market, and you come to some conclusion to say that means speculation does not matter, that really does not follow because what really matters is how the futures market actually functions with regard to kinds of regulations in place, and that is really what has drawn a lot of the criticism with regard to the role of the speculator, not the existence of futures themselves.

DR. NESBITT: Along those lines, I was dumb enough last year to sit around and read some economics and I got to the theorems on the economics of uncertainty, and what they said was, that we have complete -- and we are going to define what "complete" is -- forward markets in everything. It is nirvana, it is perfect. Decision-makers and corporate decision-makers and personal utility-makers can be risk neutral because they can throw off all their risks in the perfect complete forward markets, and the frictionless forward costs less. So this is very interesting. That is the way Enron -- I hate to say "Enron" -- that is what they thought they were striving for. You know, they read those things and they said, "We have complete frictionless forward markets, you can trade anything you want, including your children, kidneys, whatever," they did a little of that. Then it is going to be perfect. You can have people that are able to be -- all companies can be in a risk neutral fashion, they can just look at the mean values, they can put some uncertainties on it, and everything is great. Now, what is the problem? And this is the one that, when I lie down at night, I have to take lots and lots of lots of Pepto Bismol. Where are we headed as policy-makers these days? We are running markets incomplete. This is cancer on [inaudible] [13:15], I think. "We won't let you trade certain derivative products because those are bad." "We won't let you make certain speculative trades because those are bad." I personally do not believe that. I believe more trading is better across the board, more speculative trading, more stupid trading, more smart trading, more every trading is better. And there is one more reason for that, too, and that is what is called price discovery. I will not tell the oil company, but it was about in 1980, I went to an oil company and I said, "What in the world is going on here? You guys are setting up a trading business? I mean, God, don't you make more money on one oil project in Sumatra than you do on this?" He said, "You'd think so. The reason we're doing it is not because we want to hedge, or speculate, it's because we want to discover the price. We want to know what the price is. We want to see it, smell it, taste it, touch it. We've gotta know what that price is." I go, "Well, why?" "Because every two-bit customer comes to us and wants a discount relative to the price. We are discounting their confidence away." And the example that he used was, well, you know, you go down to buy a gold ring, do you have to guess the price? No, you know what it is. Just go read the paper. But if you did not know what the price was, if it was not discoverable, and discoverability comes out of trading and speculation, and everything else, you can go buy your wife, your girlfriend, or whatever, a gold ring and you know exactly what the price of gold is on that day. The price is discoverable. There is just a huge amount of economic efficiency benefit in that. So I am one who believes in economic fairness -- more trading is better, not less. I think we are on the wrong policy track when we start restricting trading of certain commodities. I think Ken has one really good point, and that is the conditions of trading. And I think what you said, Ken, and if you did not say this, correct me, is there had to be some reserve requirements, that is really what you are talking about is reserve requirements so Dale Nesbitt cannot go out and trade goldmines in South Africa because I really do not have the reserves to deliver. But subject to that, I do not --

DR. MEDLOCK: That is what it amounts to, yeah.

DR. NESBITT: Yeah, I do not see why -- I just do not see all the speculative frenzy that we got into, I just do not see it. But trading is good, more trading is better.

MR. MILLER: Would you go so far as to say trading makes discoverable the interactions of all the other physical uncertainties?

DR. NESBITT: Well --

MR. MILLER: That somehow the market can put a price -- can internalize all those aspects and come up with the price that, once in the future you actually realize all those outcomes, that ends up being the price?

Dr. NESBITT: No. You know, I do not know the answer whether more trading gives you less volatility or more. What the theorem says is that, if you have perfect frictionless forward markets that are completely free entry and exit by everybody, then the decision-makers can be expected value decision-makers, they only need to know the means, they do not need to know the spreads. Now, it does not say whether the spreads are bigger or smaller in these probability distributions over pricing, it says they need less information to make decisions. Now, that is an interesting thought. I do not know whether the existence of futures markets renders volatility, smaller or larger. And when most people talk about policy, they are just talking about the spot pricing, anyway. I do not know the answer. Are there theorems on that? I have not seen them.

DR. MEDLOCK: Yeah, in general, the existence of a futures market, it results -- if you just think about the probability distribution of the expected price, it is going to be wider, because if you have a completely regulated market, you know the price. Right? The trouble with that is, though, in a completely regulated market, you have seven-step changes because you realize that you are on the wrong path. And that can lead to huge adjustment costs, which is really where the benefits of, you know, liquidity come in.

DR. NESBITT: Absolutely.

DR. MEDLOCK: The one thing -- the role of price discovered, that is exactly right, and you hit on the head of what we are talking about when we talk about position limits, is basically reserve margins. One interesting point, I do not know if many people in this room know, I can name five major oil and gas producers that did no hedging whatsoever. So that tells you something about the presence of the physical in the financial market.

PROFESSOR BOYD: Is that a good or a bad?

DR. MEDLOCK: Well, it has worked out really good for them. That is why I do not do it. I mean, to think about it, trading at the end of the day is a zero sum gain, so if I am a major oil producer, and I understand that in some periods I am going to make money, in other periods I am going to lose money, why do I want to invest a massive amount of capital to develop this infrastructure when I know it is not going to bear any fruit for me at the end of the day? That is the question that they ask themselves, and they just decided not to do it.

DR. NESBITT: To add to that, I think the fruit that it bears is the informational fruit, not the physical fruit, or not the -- that is what you are saying -- there is informational fruit to be borne at low costs, that is the price discovery. I think that is what you said.

DR. MEDLOCK: Well, the -- the five companies I am talking about, they are free-riding, basically, without regard.

DR. NESBITT: Yeah.

PROFESSOR BOYD: That is what I was thinking, let somebody else do it.

DR. MEDLOCK: Exactly.

PROFESSOR BOYD: All right, Ross, get yourself out of that one.

MR. MILLER: I cannot, really, I do not know how I got myself into it.

PROFESSOR BOYD: Do you want to try your point price --

MR. MILLER: Let me go the opposite direction. I could not help but notice in all the opportunities to ask questions during the day, no one asked the Energy Commission to come up with a point forecast of natural gas prices, so one gentleman did during the break, and I do not know if that is telling, but just as a matter of history, the Commission has in the past adopted a price forecast for natural gas to be used by others for various purposes. In the last cycle, we did not do that, we took a different approach, much more similar to what we have heard here today. That is not to say that people would not like to have one. Of course, they would like to have one that is accurate, and what we would like is for people who might use whatever forecasts, or range of forecasts we would come up with, is to use it intelligently and, as I added that other question earlier, that they understood the uncertainty and risks to their purposes inherent in those forecasts. Just to make sure that that is not the same as saying we do not think the Commission should do anything, quite the contrary. The level of sophistication of assessments we have seen here today is really a lot of something, a lot of expertise, a lot of thinking, and a lot of insight. And I think that is what we need more of, and we need -- I will call them the "users of the forecasts" -- to also get reflective about the limitations in insights from these assessments, and how they affect what they are specifically trying to do with it. Dr. Nesbitt was talking earlier about providing ranges of forecasts, which we have done in the past, how that might be done. We have seen examples of -- we can have six or eight experts come in and all give us a forecast, and we will end up with a range. I did not really notice any of them doing that today. We did not ask them here for that purpose, we asked them more for the analysis and the insights about the relationships and interactions. Nevertheless, I think if we were to ask for a range of numbers that users of forecasts might have some confidence in using if they understood the risks relevant to their specific purpose. We could either come up with that, or point people in that general direction, or to the people with the expertise.

DR. NESBITT: Yeah. I like the idea of being first order probabilistic. But let me give you two caveats. One of them is, it was told, and actually both of them were told to me by my thesis advisor, the first one I remember I was blabbing about probability one day, and he looked at me and he said, "Hey, Dale, what is a probabilistic model of ignorance?" That is ignorance, too. Do not use probabilities just to cover over your ignorance. And boy, is it easy to do that. If you have ever built a Monte Carlo model, you have done that, you have just gussied up ignorance with fanciness. Okay, so we have got to be really careful when we generate these probability distributions or high mediums and lows on price and we know what we are talking about, maybe it is a 20/50, 80 percent like the USGS does. I think that kind of thing is really valuable. The second thing he told me, and I have never forgotten this, and nobody should ever forget it, please raise your right hand and repeat after me, "Information only has value if it changes a decision that you would otherwise make differently." And the example that I always used is cigarette smoking. Tobacco research has zero value to Dale Nesbitt. I have never smoked a cigarette in my life, I never will smoke a cigarette in my life. It does not really matter to me whether they cause cancer because I am not going to change any decisions. Now, Starbucks coffee, on the other hand. If I learn that stuff is as bad as my mom told me it was, I am going to change how much I drink. You really think about that, you guys do not have to be worried about uncertainty on things that do not matter. You ought to be worried about uncertainty on things that do matter, things like I think that the briefings today were pretty good, they were focusing on things that I think matter -- demand, supply, pipe, LNG, what is going on in Russia, whether or not you are going to have a lot of displacement out of Asia and on to the West Coast. Uncertainties in those kind of things, you can think about, and I think you can think about those in a focused sort of fashion and use a model to glue them together. Just uncertainty in price. I will give you one other great great -- at least for me -- anecdote that was the lowlight of my career. It was 1982, I remember, and that was the Alaska gas pipeline and they hired a consultant. I could tell you his name, he is still practicing, he came to me and he said, "I'm going to do a Delphi survey. I have 35 probability distributions from 35 of the most esteemed energy experts in the world, and you, Nesbitt. I want your probability distribution of oil price, and I want your probability distribution over gas price." And when I put 35 of these probability distributions on a piece of paper, and then I am going to go tell Northwest Pipe whether they should build the Alaskan gas pipeline. And I remember, this is 1982, remember, real oil price was actually quite high then, it was destined for a big fall. I had probably the lowest probability distribution on oil price and gas price of anybody in the survey. Why? Because I had a model. I did not know what it was going to be and I was still a little high, but I had a model. This was the most misleading study I have ever seen in my life because he told me, "Go ahead." One guy had $120 -- 1981 dollar mean value -- for his oil price. So the other thing I would caution you against, I saw some of it today, when you see forecasts published on a slide, "Here is Altos, here is Rice University, here is Woodmac," throw it in the can. It is worth zip, zero, nada, it actually has negative value. You know, if I gave you the speeds of light that were calculated through the 19th Century, plotted on a chart, what good would that be? None. That stuff is awful. You have got to get really fundamental about thinking about uncertainty. So my thought is, as you do this, and I think you are prepared to do that, think fundamentally about shale gas, think fundamentally about demand the way Ken was talking about, and then your probability distributions over price derived with a model tend to be pretty good in my experience. You do not get stuck with these point forecasts. So that is my long -- think fundamentally about probability, do not just gloss over it.

MR. OSTEN: We do, uh, incorporate uncertainty in various ways in our forecasts. I think I would just preface that by saying that our Global Insight and colleague companies probably produce several hundred thousand different forecast items, everything about any particular country in the world, and all of the commodities, cost indices, supplies and demands, and with several hundreds of people working on forecasts, trying to be consistent, trying to have the same time span, is of course a challenge. Everything starts with the world oil price and works through the U.S. macro, and then to the world macro, and then to the other items. And one aspect you get from trying to be comprehensive and trying to feed through is a consistency, or at least some essence of what the relative price is, and the relative values are. And it is not just, say, the price of oil vs. the price of gas, and many of the other things that go into these decisions. When we look at our gas market, we spend a lot of time looking at the coal markets, as well. And relative price of gas to coal has historically been a very important variable for many of our customers. And even in Europe, we have consultants who are doing many studies on coal for a continent that is trying to get away from coal. On probability distributions, I like what Dale and Ken have had to say on these issues. The difficulty I have with probability distributions is that, when we start looking at the standard deviation and the distribution itself, is we tend to go back to historical values. And if you did a probability distribution on Henry Hub in 1995 and looked at the price and it varied between .98 and perhaps $3.00, and then did a probability distribution of future forecasts, and you get a very different answer than if you did it now, just because the history has changed. So when you look at scenarios, you know, Ken talked a lot about the scenarios that he did, but in the sense of, say, what sort of scenario is consistent with the low price of natural gas, or what type of scenario is consistent with the high price of natural gas, or what scenario is consistent with the cyclical price of natural gas, you get, I think, a better education about what the probability distribution should look like. It used to be that everybody did a best case, a high case and a low case, and I think we have as an industry and a forecasting industry, we have moved more towards scenarios and more towards in-depth statistical analysis with just a simple high and a low. And I think that is what the recommendation -- a focus on relative prices, trying to get some -- education yourself with scenarios about what high, low and cycles could look like, would really help a lot before you get into probability distributions.

DR. MEDLOCK: Uh, the only thing I have to add there is a point that was just made, actually, about probability distributions sort of being myopic; they are because they do rely on where you have been, not necessarily on where you are going, and that is really what I was addressing, and this is at its core one of the criticisms of all the macro models that evolved in the '70s, they were not able to capture some of the short term deviations and macro-economic variables that were seen, and so they were poor predictors of the near-term. Longer-term, however, you really do need a structural model because there are things that structurally change about the marketplace. So that was my point about understanding what makes the outcome change, understanding the sources of uncertainty on long-term forecasts. A probability distribution, quite frankly, does not mean a lot in a very complex structural model if for no other reason that a lot of the variables that you put in, a probability distribution would be subjective. And so it is really going to be up to you as the user to define that distribution. So at the end of the day, what have you told yourself? Well, exactly what you thought you would tell yourself. So it is more important to focus on the sources of uncertainty and understanding what they mean than that, when you are looking at things in a long-term setting. For short-term analyses, it has been shown time and time again, pure time series econometrics is hard to beat, just to be blunt, it is hard to beat.

MR. MILLER: Nobody wants to take on accurate point forecasts?

MR. OSTEN: Well, one thing Global Insight has to go through, and it is a good thing, if you look at the Wall Street Journal or other periodicals that rate forecasters as our macro forecasters go through, I think, about once a quarter to get rated on how they have performed against other forecasters, and I think there are some people trying to do that with price forecasts, as well, we do as a macro forecasting shop, we have a very good track record with forecast accuracy, it is very interesting to look at the track record for the forecasts. And I would recommend we are never going to have an accurate point forecast. Forecasts are always going to be wrong. But you can always have a track record -- track records are sort of [inaudible] [32:53] law or the forecaster. I do a track record on my forecasts, not for public consumption, not necessarily for public consumption, but it is a very useful tool is to try and understand why were we wrong, why did we catch this uptick or downtick. And it is also a very useful exercise to take the models and go back, and we forecast how much can we explain of why prices ran up through July of 2008, and why they collapsed since. What is it in our models that explains this? We have ability to explain. I think Ken hit the point, econometric model that is well-defined and frequently estimated probably would have a little better chance of doing that sort of cycle of prices than a very big blocked or structural model, both have the purposes.

MR. MILLER: I have got one question of --

DR. NESBITT: Did you want to continue because I am going to change the track record in a minute.

MR. MILLER: No, go ahead.

DR. NESBITT: There are a couple of very interesting stories about track record. I do not believe in track record, I think it is largely random. There is a famous story, I believe it was Tim Hardaway, he played in the NBA, and there has always been people who believed his hot streaks and cold streaks shooting three points, right? He hit five straight. The next night he comes out, eyes closed, misses nine straight, angry, throws the ball to sidelines at some event. So they built all kinds of models of Tim Hardaway's shooting percentages and, you know what the found? Far and away the most descriptive model for shooting percentages was a binomial distribution with a P of .41. That was the best explanation of his hot streaks, his cold streaks, and everything. I do not believe in track records because there is too much randomness in track records. I believe in due diligence when you are doing the work, and thinking when you are doing the work. So if you believe that there are no hot streaks in the NBA, there are no cold streaks in the NBA, it is just a binomial distribution. There is a lot of that in forecasting, too. As we sat here today, some still have a high estimate of certain things, some of us will have a low estimate of certain things. I think you have got to do it exactly the way Ken did, debate it out, think it through, come up with a partially subjective, maybe an objective, probability distribution, although we Bayesians* do not think there is any such thing as objectivity, and run all of them together, a model of all of them together, and that will give you a pretty good estimate. So if you want another example, like track records, do not work, read a random walk down Wall Street, you would throw all the random guys out and just build models. So it is what you have been doing, you have got to work at it, there is no free lunch in this stuff. It is hard.

MR. OSTEN: Well, I believe in track records. Listening to a history of philosophy and the part about the people who were developing models of the solar system, planets circling the sun, there are several iterations of that, but it was really a point, I believe, where the idea of using models to describe a physical process, or a process that could be measured, and then improving upon the models to get better measurement. And the purpose of track record is that if your model is not tracking, it is not tracking the revolution of the earth around the sun, then you start looking for variables that might help you to explain better that revolution, similar when Christ forecast. There are a lot of new variables that have emerged in the last 20 years, and from an international perspective, you mentioned the earthquake in Japan, a big issue in gas markets is the recession in Europe, they are not stimulating their economies, their demands are down, they are displacing Russian gas at the present time, they may fill up their storage early and have a lot of gas to displace to the U.S. and the Atlantic Basin, and it is just examples, this international arena, how do you incorporate all those international aspects into a price forecast for North America? At what point do new variables enter the model? So just tracking the model and looking at how the world is changing can be a very useful exercise.

COMMISSIONER BOYD: I am looking back at my notes and it says, "Why do we even bother?" At first, I wrote down, "Because it is there," then I wrote down, "Because they pay us to do this." Anyway….

MR. MILLER: Well, I think that comment was about why do we bother to make that point, forecasts. Right? Or reveal one once we got it.

COMMISSIONER BOYD: Well, I remember in 2005, the last IEPR that I was deeply engaged in, saying -- and I had bit my tongue when I signed the Hearing Notice here, when you put the question in it, being part of the group that said, "No, no, never, not ever again." You know? Scenarios. But I am also opening to always questioning what you just did, and ask the question again, so you asked the question and here we are again.

MR. MILLER: I was just going to make an observation about not seeing any mention about coal gasification in the presentations as a source of gas. I did see IGCC, I think that was excluded from the automatic capacity expansion as being too expensive, as nuclear was, but what I am not sure is if the subject was outside the scope of the studies, or, by consensus, it is not likely to happen.

DR. MEDLOCK: No, I can tell you in both the gas modeling work and the trying to understand the effect of binding carbon constraints on energy markets, that work, IGCC and coal gasification is definitely a very real part of what we are doing. And one of the biggest uncertainties about that particular technology is cost. And if you use the cost that the Office of Fossil Energy at the DOE uses, you have a much more favorable view of the world with regard to IVCC than if you use an industry vetted cost, which is much higher. But, again, you have to ask yourself the question, the DOE cost, is that sort of what they think costs will converge to? So a long-run cost? And is the industry vetted cost sort of a myopic view? Are we at a high, and that is what everybody sees right now, so therefore they say it is not feasible? So at the end of the day, what we do is we run models with both sets of costs so you can understand what the influx is. But, yeah, it definitely is a part of what we do and it is technology, quite frankly, that has been changing at the margin for a while, so I fully expect to continue to do so.

PROFESSOR BOYD: But it is kind of like, "Future Gen, where are you?

DR. NESBITT: And that question is very relevant in liquids. I mean, there is a lot of change in coal to liquids, gas to liquids, shale -- first job I ever did in 1974 was to figure out whether Gulf Oil should bid on shale tracks in Colorado. They did. Lost a lot of money.

COMMISSIONER BOYD: Now, you reference gas and liquid, and that is the first time today I have heard that.

DR. NESBITT: Let's chat about that. That is a very interesting one. Could I have two minutes to talk about that?

MR. MILLER: Sure.

DR. NESBITT: I have spent a lot of time looking at that in the last year. Think of yourself -- think of the trap down in the ground with liquids and gas in it, gas and liquids occur together, like Prudhoe Bay. What fraction of the total btu's appear in liquid form? Well, 5, 6 about, only one-sixth is gas, so there ain't that many btu's in a Prudhoe Bay gas cap. And this is one of the big problems with gas to liquid, there ain't that many btu's out there when you start looking at transportation fuels. Okay, and so you take the Prudhoe Bay gas cap, give or take 40 tcf, that is give or take 40 quads, and it is going to cost you about half of that, and we can debate whether it is half to turn it to liquid, so you have got about 20 quads of liquid. Well, that is half a year. We are 20 million barrels a day -- that is 40 quads a year. Gas to liquids is very difficult because of the low btu density and natural gas and oil wells have gas. So you have to look for massive massive massive concentrations of methane, like Ken was talking about. The Uruguay field, the East Siberia field, the Arctic fields, the Qatar North field, these kinds of places. And even there, 2,000 tcf of gas, there is a lot more oil sitting down in the ground, so you lose a little on the btu's. And right now, the gas to liquids technologies tend to be pretty endothermic. You have got to pour a lot of it in it, oh, that means you lose a lot of energy as you move from gas to liquids. There are places -- we have got an oil to oil model -- where you will make gas to liquids, and that is the place where you cannot get the gas out, not near the water, no market for it, arctic, East Siberia, and places like that. Gas to liquids is fairly tough. And one other issue along that -- I have been giving briefings to senior management on this -- everybody needs to hear this. If you have got yourself a -- I think it is a 4,000 pound vehicle, well, a 4,000 pound vehicle, right -- 20 gallon gasoline tank -- gasoline -- if you took the gasoline in that tank and you used it to raise the vehicle off the ground, how high would you get it?

UNIDENTIFIED SPEAKER: How are you going to raise it?

DR. NESBITT: Just take the thermal energy that is in the gasoline and move it MGH, how high do you get it on MGH? Very interesting question. Any guesses? It is 91 miles. Do not sleep with your car in the garage. This is why methane powered vehicles have so much trouble, you cannot get the btu's on the platform. You cannot get the btu's out of the methane and into the liquids very easily. The thermodynamics of going from gas to liquids are hard. The thermodynamics of going from liquids in the auto sector to anything else are really really really hard, they are really hard. I hate this when this happens, but it is really hard. So gas to liquids is tough.

COMMISSIONER BOYD: There was a track we did several years ago as a substitute for diesel fuel for a lot of environmental reasons in California, but as we looked into the economics, they just were not there and the economics appeared to be there for the Europeans, so deep into diesel, to take some of that Middle East fuel, but it does not seem to work anywhere else, from my perspective.

DR. NESBITT: Let me make one other comment on that. That is exactly right. If you look -- the other thing that makes the Europeans so attractive, it is very interesting, if you look at our distribution costs for refinery to tank, we are about $40 a barrel, so the retail price here is about $40 a barrel than the refinery -- you know what it is in Europe? It is $180 a barrel. And so, when you take $180 a barrel minus $40 a barrel, so it is $140 a barrel, and you add it to our retail price of gasoline, absolutely, gas to liquids and a lot of other fuels makes sense in Europe. They have massive distribution costs in taxation, we know that.

COMMISSIONER BOYD: All right, Ross, it is all yours again.

MR. MILLER: I have no other questions. I would like to open questions from the audience or the Internet to the panel while we have them here.

COMMISSIONER BOYD: Anyone out there want to take advantage of these minds, great minds all sitting together at a table in this rare occasion --

MR. MILLER: Three, at least.

COMMISSIONER BOYD: And Ross.

MR. MILLER: Don't say -- "and Ross." [Laughter]

COMMISSIONER BOYD: You invited that.

MS. KOROSEC: All right, the lines are unmuted, so if anyone out there in the ether would like to take advantage of this wonderful opportunity, now is your chance.

COMMISSIONER BOYD: Is there anyone out there?

MR. MILLER: We have one over here.

COMMISSIONER BOYD: Oh, good. I did not see you, Marshall, hiding behind the TV for a while, on my line of study.

MR. CLARK: I was just hiding over there. Marshall Clark from the Department of General Services. As a point of information, I buy natural gas for most of the public sector facilities, the large ones here in California. I just had a strange point to make, I really appreciated the information presented here today, and I speak now just as a very practical kind of issue, and that is that the Energy Commission gas price forecast has a lot of use, at least to my customers, and specifically in the case where they are trying to make the decision about whether or not to build an energy project, most typically a co-generation project. And the thing that was most valuable about the Energy Commission forecast, we never really thought that it was accurate as a point forecast, that was how we took it; we understood that it was not that, but the value. And I submit to you something to consider, it was the relationship that there was the gas price forecast that exactly matched up with an electrical forecast, and when you are trying to do an analysis of an energy project, like co-generational projects, knowing that the gas price and the electric price were on the same basis, even if you just took it as the ratio, and you were not talking about $.50 and $.15 of kWh, but you knew there was a ratio, and therefore, when you did your analysis of a prospective energy project, you could do the sensitivity, the price sensitivities, but you had the ratios right. And we have -- I am bold and crazy enough to do gas price forecasts, I have no courage whatsoever to do electrical price forecasts, even though theoretically if I know one, I should be able to come close to the other. The Commission did serve a very useful purpose with that particular ratio. There are people out there who need that information, who I suspect cannot derive it any other way. And it is not so much a question, it is just an observation that, while I understand all the constraints with point forecasts and these very deceptive and even get you into a lot of trouble, that particular ratio in the Commission's price forecast was very very useful to at least a certain set of customers.

COMMISSIONER BOYD: Thank you, Marshall.

DR. MEDLOCK: Let me just add one thing. I think what you just said is actually incredibly true and incredibly valuable. Understanding variable relationships, this is one of the things I was really trying to highlight, is really one of the most beneficial things about forecasting exercises. So understanding fuel price commodity price relationships is incredibly important because it helps you not only, when you are thinking about planning for power projects, but upstream oil and gas developments, if you are going after an oil field that has associated gas that you can actually market, it can actually change the economics, depending on what that oil/gas price ratio looks like. So it has a lot of value. But, there, you are not really restricted to what I would call a "point forecast" because that point can move; as long as that relationship is stable, there is a lot of value on that. And I think that is one of the things you get out of these long-term structural models is you have forces that will drive some degree of stability in a long-run relationship. Yeah, absolutely, I mean, that does not surprise me what you just said.

DR. NESBITT: One question you did not ask is the most frequent -- this is one that everybody asks and it has not been asked -- so what good is the NYMEX futures pricing?

What good is the NYMEX futures -- isn't that great, shouldn't we all calibrate to it? Well, I will let it go. When I did the bankruptcy a couple years ago, there were three modelers, two of them just used the NYMEX for the first two years, this is right before the big price run-up in natural gas, and then they graphed some half-baked subjective estimate for gas price on the back end of that, and then they ran a power model. This was deplorable. Now, all said, I would like to get the other panelists and anybody in the audience to talk. My empirical research, which is non-scientific, non-academic, and non-publishable, suggest in very worst forecast price a year out is NYMEX. It has been horrible -- you can bet on it. It has been a horrible predictor, and it is not really designed to be a predictor. It is today's idea of what tomorrow's price might be, but it is not tomorrow's price. So I recommend pretty strongly that the NYMEX price is not something to be calibrated to, it is not really something to be plotted, it is something to be bet on if you were a betting person, but policy people are not betting people. You know, to comment a little bit on it, I think the NYMEX forecast is badly misleading.

DR. MEDLOCK: Uhm, well, the last thing you said is actually part of the problem, it is not a forecast. The strip on the NYMEX is a -- it is a price, but it is a price of the market for risk, it is not a price in the market for a physical commodity, it is tied to the market for the physical commodity.

DR. NESBITT: Right.

DR. MEDLOCK: But there actually has been some work done and the name of the author escapes me, but I think it was published in the 2004 -- it was a paper looking at whether or not the NYMEX strip was an unbiased predictor of spot natural gas prices, and it is a horrible predictor. So and this was actually econometrics and I cannot remember the name of the author for some reason, right now. But you could probably Google it and find it in a Google search, but it is out there. And there is evidence to that effect, so….

MR. OSTEN: I find a little different information in the NYMEX. I always like to look at it for its seasonality. And seasonality -- I tried the test and I said, "Why are these people betting on the seasonality of the NYMEX? What does it relate to?" And I tried plotting the seasonality against other indicators, and I finally plotted it against total degree days, heating and cooling, and I got a pretty close match. And it tells me that the traders, or those who do any analysis at all, are just looking at normal heating and cooling degree days to do the seasonality. I was interested in that because I happen to have spent a lot of time in Calgary, and when Amaranth was

-- a fellow at Amaranth was driving around Calgary in his Jaguar, or Lamborghini, or whatever, and making his billion a year, he bet the bank his company, anything else he could bet, that the spread between March and April, I think, 2007, NYMEX futures, would be wide. And he lost. And he lost the company. And he had court cases and whatever since. I looked at the April/March spread, I looked at what the NYMEX had said before and what it said after, and I tried to look at all the history I could, but what I concluded was that, historically, March/April price differential has essentially been zero, on average. And there was one point, if you remember back when the charts were shown this morning, the end of February 2003, I believe it is, there were one or two days when the price of gas went up to about $19, and consequently, the March 2003 bid-week* [53:43] price was like $9.95, and then it fell apart in April and we had normal weather, just like a couple-day phenomenon. And if you looked at that, you said, "Gee, if I had that $6 billion in the summer of 2002 on the March/April spread, I would have made about $18 billion." So there was a glimmer of hope for this trader. But that seasonality is interesting. I have tested the seasonality. It bears no resemblance to actual historical seasonality of gas prices. So, anyhow, that is some useful information, at least what people think seasonality is going to be. The other thing I look at is the change from month to month and what it has been on average, how many ups, how many downs, what creates ups, what creates downs, because I have made my living being a forecaster for 35 years and I have a lot of things that I look at. It is very difficult to explain it as anything other than a random lot, but the mean change I see from month to month over about the last decade has been about $.20, and that is sort of random whether it is up or down. But $.20 is a fairly substantial amount of money if you are looking at today's gas price. So that is interesting. Then look at the change month to month as you go further out, and you find that it is usually a lot smaller, but people create a strip and they sort of work off whatever happens today, June 16th, 2009, is reflected in the price out in December of 2018, just because that is the way the futures market works, as Ken was saying. When you get to December of 2018, what happened today will have no bearing on that price, and that is a source of some embarrassment in the futures market. But there is information there. I have tested it for information and I find information in the futures market, not necessarily what you want to hear, but there is some there.

MR. MILLER: Thank you. Anyone else? C'mon up, Leon.

COMMISSIONER BOYD: C'mon, Leon.

MR. BRATHWAITE: Again, I am Leon Brathwaite. You know, Dale, I know that you are supposed to be an expert here, so I am going to take issue with you. You have just said that NYMEX is a horrible predictor, and that it means nothing. Am I quoting you correct?

DR. NESBITT: Pretty close.

MR. BRATHWAITE: Okay. Now, so I find it very difficult to understand this statement. Then we must be looking at some of the greatest amount of irrational behavior ever experienced in human nature because people are taking their hard-earned money and betting on the direction of prices, and you are saying that means nothing? I find that hard to believe.

DR. NESBITT: I did not say it meant nothing, I said it meant nothing predictively. I said people bet on it. It is something you can bet on. It is something -- exactly what Ken said -- if you want to take risks, you know --

MR. BRATHWAITE: Well, then you must predict them, right?

DR. NESBITT: It is not a good predictor. What I really meant to say was, and I will clarify, was if you look at NYMEX today, and let's just take one year forward, and you look at the price one year forward that actually occurs, and you plot what it said a year out vs. what actually happened, it is deplorable. It is almost no information at all there. So if we are sitting there with today's NYMEX price, which is extremely cantango, it is up around $7.00, I have not looked at it, that is a pretty bad predictor based on historical data of what the price will actually be a year out. Leon, you can go bet your entire paycheck on it. You can go along if you want to, but that is not a predictor of what the price is going to be, it is just something that everybody in the market is willing to bet with you on.

MR. BRATHWAITE: Okay, and I truly accept what you just said, but the point is here, though, as expectation changes, prices change.

DR. NESBITT: Right.

MR. BRATHWAITE: Right?

DR. NESBITT: Right.

MR. BRATHWAITE: So why is that different from any of all forecast that we put out? They are all forecasts and, as expectation changes, prices change.

DR. NESBITT: Yeah, but see, here we are today -- and this is the important piece, and I think Ken touched on it -- you are sitting here today, you have got to lay down your bet today, you have got to go home to your wife and say, "You know what? I am going to put my entire income from next year, that seven figures that I am going to make this year, and put it on the red on the roulette wheel. I am going to go along with NYMEX." You are done. Your bet is in the can, baby. Whatever happens tomorrow has no effect on you, the only thing that has an effect on you is what happens a year out. And I am saying, there is not very much information value in the forward strip today as to what really is going to happen a year out. You might as well go to Vegas and stick your hard earned money on red.

DR. MEDLOCK: I will just add something because, Leon, you actually make a very good point, you know, what is the value? The value to a trader, and this is why there are teams of fundamental analysts on any trade floor that are looking at medium to long-term market trends. If the trader sees a market that is heavily cantango, but the fundamentals do not support that, that tells the trader what sort of position to take in that particular market. So what they are basically doing is betting financial vs. fundamental.

MR. BRATHWAITE: Right.

DR. MEDLOCK: And that happens a lot. At the end of the day, the NYMEX, on the day that let us say you are trying to bring the price to December 31st, so that is the Jan. 1 settle, right? So when you get to that time point, that NYMEX contract, the price for that contract, has to be the same as the price in January, right? Or else there is a tremendous amount of arbitrage opportunity.

MR. BRATHWAITE: Correct.

DR. MEDLOCK: So that contract price will converge to the spot price at the end of the day.

MR. BRATHWAITE: Yes.

DR. MEDLOCK: That will happen. But the price a year from now? And there has been work done on this -- it is not a very good predictor of what the price will actually be at any given point in time. That is all.

MR. BRATHWAITE: I do not doubt what you just said, Ken, but I am saying that is no different from any other forecast that you produce, I produce, or they produce. It is no different.

DR. MEDLOCK: No, I know. But I guess the difference is what the NYMEX strip is representing is a collection of prices that people are willing to do business with. That is all it is. I mean, because you are talking about people trading a January contract, they are going to settle on a price, and that is what the price on the strip is going to be, but that is really indicative more of the risk that that is where the market is going than what people fundamentally believe about the market, because the people on the speculative side are the people that are willing to provide risk, they are actually believing, "Well, hey, I think that things are going to move much more in my favor than what this price indicates." The guys who are hedging risk, so the suppliers of risk, they are actually believing, "I believe things are going to move much more in my favor if I go ahead and go do this." And so you have got a really divergent set of views, and they are willing to transact at that price.

DR. NESBITT: That is exactly right.

MR. BRATHWAITE: Okay. Thank you.

DR. NESBITT: One other quick piece of data on this and, Ken, you may have some comment on this, it has been in the press. Qatarians have a bunch of LNG tankers parked at Mallorca and parked at Gibraltar, and parked all over the world. And on an LNG tanker, you can hold liquid for, what, about ten months or something, you can keep it cold, it is easy. And here is the rationale. You know the NVP price is what? $4.50 or $5.00, really cantango, it is $9.00 in November. The U.S. price is just $3.50 now, really cantango, it is $7.00 in November. So the Qatarians are racing to go. "Okay, I'm going to tie up the boats, throw down the anchor, I'm going to hang out in the Greek Seas, have a great vacation, and we are going to sell it in November. And we have got a $4.00 profit locked in." Smart decision? We do not know. You know what my dad would have done, he would have dumped the tankers now because he made a quarter, and then go back and get another load for November -- because what you are doing is you are pulling 35 years in the future out of the north field. I think it is dumb thing to be doing, I think it is supremely dumb. They should just be running at 100 percent load factor because they are going to have a boatload of LNG in November. And what they are doing is they are playing this game, they are saying, "Hey, hey, hey, we have got a $3.50 profit locked up, we are going to swim in the Aegean in the summer, take our money in November, and we can lock it in. They can contract for it, and they have. Okay? But is $7.00, or whatever it is at NVP in November, a good guess what the price is going to be? The answer is no, it is not. They have contracted it, but just like Ken said, there are a whole bunch of traders out there, it is a zero sum gain, some of them are going to take big losses and some are going to make money. And he is right, that is just the dollars at which people are willing to do business, that is all it is. Of course, at NVP in November, it could be -- if it is like last year -- $30 in ncf, in which case, if you have contracted for $7.00, you are kicking yourself all the way back to Doha.

COMMISSIONER BYRON: Maybe it is those Somali pirates that are causing the swim.

DR. NESBITT: Yeah, they did not anchor next to those guys.

MR. TAVARES: Okay, I guess that concludes our panel discussion. Are there any comments from the public? Well, Commissioners --

COMMISSIONER BOYD: Is there much public?

MR. TAVARES: A few. Well, I think that is all we have for now. We thank all the presenters today and you for listening. I think we had a good discussion.

COMMISSIONER BOYD: I thank all of our presenters, everyone today, including our panel members here. I found it a very interesting day, personally. It beats the heck out of what I do most days of the week around here, and hopefully it helps us with our future on how to deal with gas prices. So thank you all very much. And I guess we will stand adjourned.

(Whereupon, at 4:29 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, TAHSHA SANBRAILO, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this _____ day of June, 2009.

____

Tahsha Sanbrailo